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CIVIL ENGINEERING LABORATORY COGENERATION ANALYSIS PROGRAM - CE--ETC(U)
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CIVIL ENGINEERING LABORATORY
Naval Construction Battalion Center
Port Hueneme, California 93043

Sponsored by
Chief of Naval Material

9 Contract rept. Mar-Sep 80

6 CIVIL ENGINEERING LABORATORY COGENERATION PROGRAM - CELCAP USER DOCUMENTATION

11 Mar 1981 12 119

10 Penni/Bradford

An Investigation Conducted by
TWO D ENGINEERING, INC.
P.O. Box 2857
Oxnard, CA 93034

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15 N00123-78-D-6892

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20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

This report documents input requirements for the CEL Cogeneration Analysis Program (CELCAP) and includes reference material from which much of the input data can be drawn. A sample of each card is provided. No program listing or output listing is included, however.

CELCAP analyzes the performance and economics of cogeneration systems utilizing combustion turbines, diesels, or steam turbines. The effects of engine combinations, engine size, control mode, use of peaking engines, utility rate structure, sale of power to the utility grid, fuel type, fuel price, and future cost escalations can be determined by varying the input.

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20. Continued.

The program computes design point engine performance, compares thermal and electrical loads against engine output, adjusts engine output according to the assumed control mode, and calculates the resulting instantaneous and life cycle costs of operation.

The program is written in FORTRAN IV for execution on CDC systems with 60 bit words.

INTRODUCTION

CELCAP is a computer program written at CEL for the analysis and comparison of cogeneration system alternatives at Navy activities. The cogeneration system may stand alone, or it may be fully integrated with the utility company grid. The concept of a fully integrated cogeneration system is depicted in Figure 1 (page iv).

Features of the program are:

a. Analyzes steam turbine (single extraction or back pressure), combustion turbine, and diesel systems;

b. Handles any mixture of five (5) or less engines;

c. Compares operation of system assuming three different control modes (modulation to follow thermal load, modulation to follow electrical load, and constant operation at full load);

d. Can analyze effect of installing peaking engines as well as cogeneration units;

e. Accurately predicts off-design performance of engines;

f. Predicts cost of purchased electrical power and revenues from sale of power to grid with rate structure algorithm (algorithm can be readily modified for different rate structures);

g. Input data includes typical steam and electrical load profiles for work days and non-work days of each month, engine design point data, fuel prices, rate data for purchased electricity, and assumed escalation rates for fuel, power, and O&M;

h. Output data includes comparisons of the system's steam and electrical outputs vs. loads (plots and tabulation), monthly and first year breakdown of costs, and annual cost projections throughout the life cycle. Much of the information needed for completion of MILCON request form 1391 is included.

This is the "User's Manual" for the CELCAP program. The manual includes a great deal of the input information required by users at the EFD's, or will specify the source of information for the user. For example, design point data for a number of typical engines will be included in such a way that the input for most engines can be accurately inferred. Basically, the user will be responsible only for providing site specific information on the thermal and electrical load patterns and the electrical utility rate structures.

CELCAP is intended to be a tool for conducting "first cut", or "fatal flow" analysis of congestion system options; it is not intended as a design tool. Because of the flexibility, however, it allows rapid consideration of a large number of alternatives and evaluation of many parameters. Experience gained by CEL in evaluating cogeneration options at several Navy activities has resulted in the conclusion that preliminary comparisons of alternatives

can be conducted at very reasonable costs with CELCAP, and conclusions can be drawn regarding the alternative(s) to be considered for more detailed analysis and design. A general description of the organization of the CELCAP program follows.

CEL ANALYSIS PROGRAM FOR COGENERATION SYSTEMS

SECTION 1. Determine "Limiting" System Performance

Input: Engine mix for analysis.
Design parameters of each system.
Site atmospheric information.

Output: Limiting electrical and steam production and fuel consumption.

Capability: Combustion turbines with exhaust boilers.
Diesels with exhaust boilers.
Steam extraction turbines, back-pressure turbines.
Peaking or cogeneration units.

SECTION 2. Determine Steam and Electrical Loads

This algorithm is site-specific. For LBNSY, algorithm considers impact of industrial loads, losses, ships, and weather.

SECTION 3. Compare Loads and System Performance

Input: Mode desired.
Identify peaking unit operation periods.

Output: Electrical and steam production and fuel consumption of each engine in response to loads and control mode.
Purchase or sale of electrical power.
Make-up steam from fixed boiler.
Amount of excess steam produced.

Capability: Control modes: Full throttle.
Modulation with electrical load.
Modulation with steam load.

SECTION 4. Calculate Annual Costs

Input: Fuel costs for each type system.
O&M costs for each type system.

Output: Annual fuel costs: Combustion turbines.
Diesels.
Steam turbine boilers.
Fired "make-up" boilers.

Annual O&M costs: Combustion turbines.
Diesels.
Steam turbines and boilers.
Fired "make-up" boilers

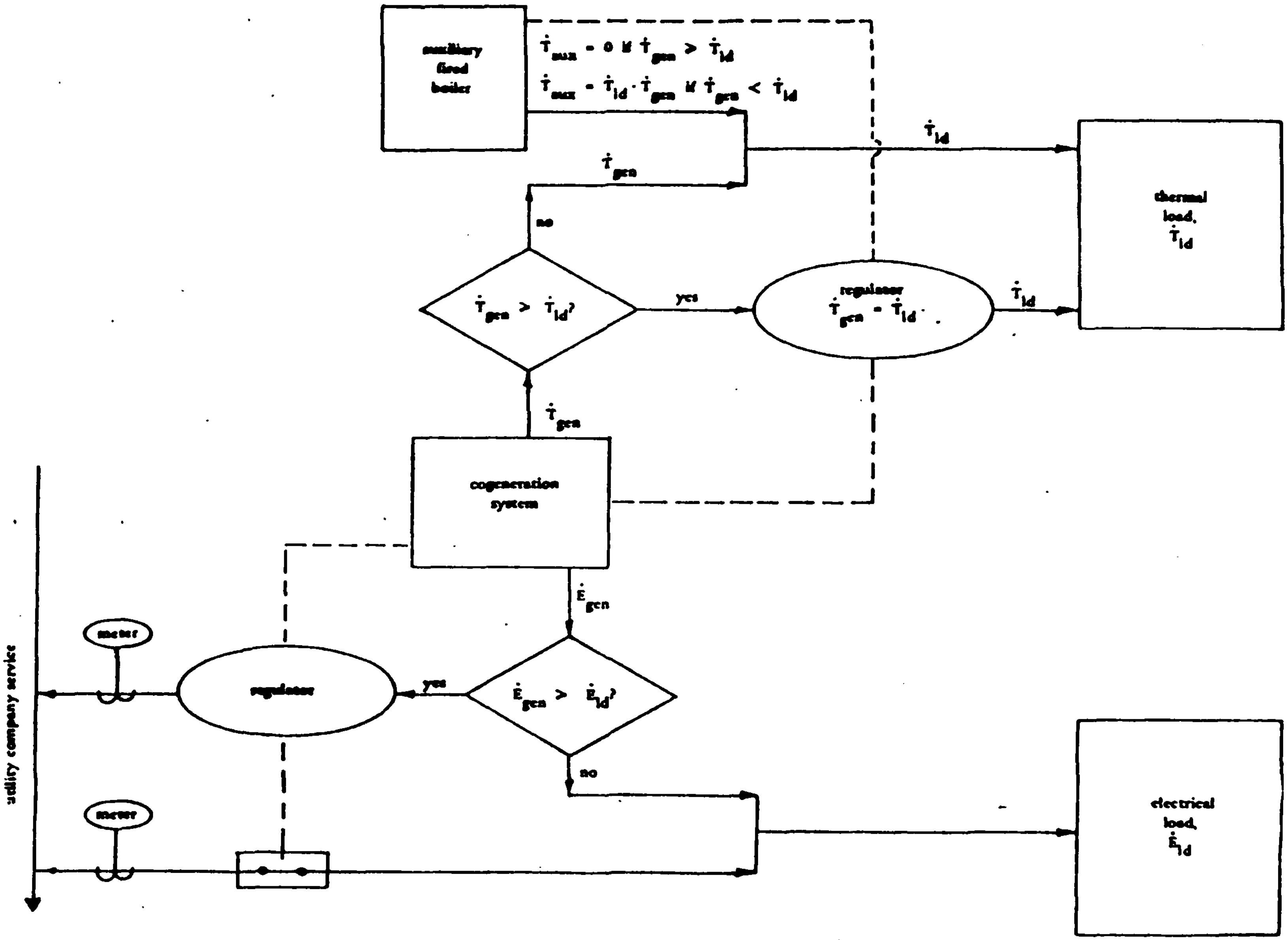
Purchased electricity costs.
Revenue from sale of electrical power.

The algorithm for cost of purchased electrical power and revenue from sale of electrical power is site-specific. Algorithm for LBNSY uses TOU-8 schedule of SCE.

SECTION 5. Calculate Life Cycle Costs (LCC)

Input: Short and long term escalation rates; fuel O&M.
Key years: Year of "present" worth.
Installation year.
Year of change in escalation rates.
End of economic life.
Discount rate.

Output: Future value for each output of SECTION 4.
Total LCC over economic life.



Integrated utility company service and cogeneration plant.

Reference material has been included throughout this publication to ease the collection of data. All input data is to be entered on cards. Valid copies of the input data cards are located on pages 81 through 111 to verify the designated format.

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TABLE OF CONTENTS

CONTROL MODES

Enter your choice in card 1, column 1.

The control modes to be considered are:

Choose 0: if the engines are run at peak electrical output.

Choose 1: if the engines follow electrical load up to their capacity.

Choose 2: if the engines follow steam load up to their capacity.

Choose 3: if all of the above control modes are to be considered.

Variable name: MOLTR
Data card sample on page 81.

REPORTS

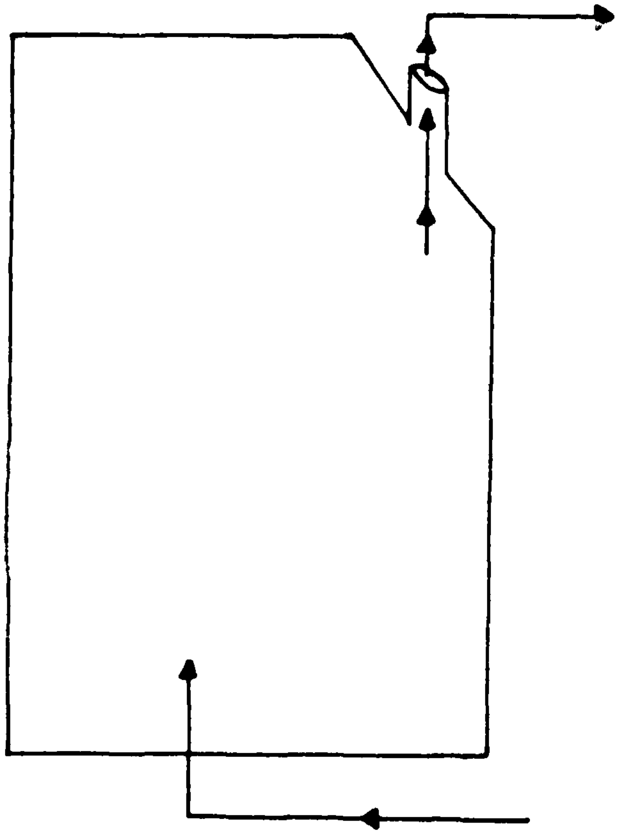
Enter your choice in card 2, column 1.

The printout will be produced in either of 2 ways:

Choose 1: if a detailed printout is desired.

Choose 2: if only engine information, annual costs, and life cycle cost printouts are desired.

Variable name: IPRINT
Data card sample on page 81.



(TEVP) the steam has PRESSURE / TEMPERATURE / ENTHALPY — KNOWN OR ASSUMED

(HLV) the heat of evaporation has PRESSURE AND TEMPERATURE — REFER TO STEAM TABLE

(BLREF) the boiler has efficiency — KNOWN OR ASSUMED

(TBLFRD) the feed water has temperature — KNOWN OR ASSUMED

THE AUXILIARY FIRED BOILER

Refer to the steam table on page 3 for specific data.

ENTER IN CARD 3:

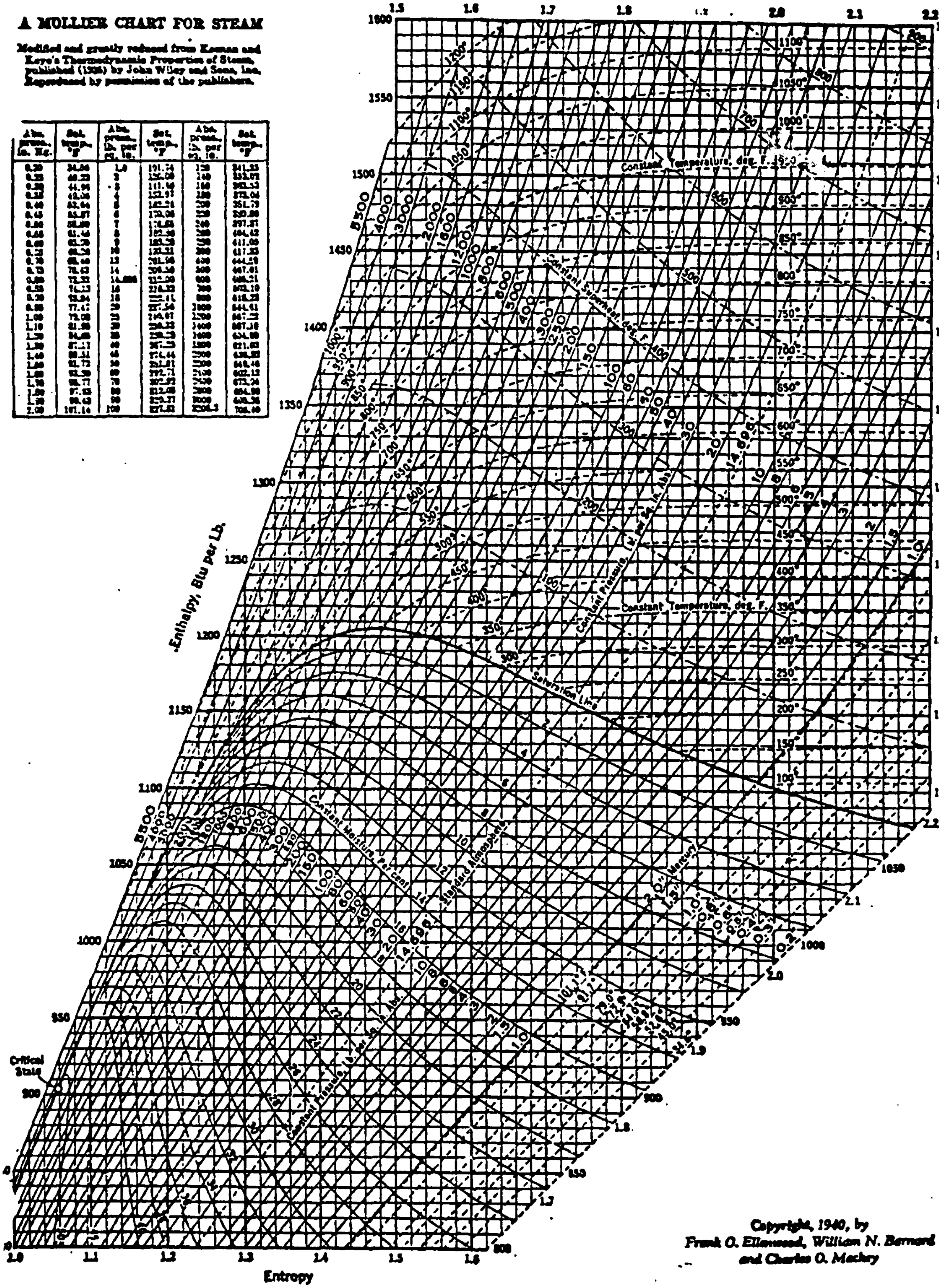
Columns		VARIABLE NAME AND SYMBOL ON CHARTS
1 thru 10:	the feed water temperature, R.	TBLRFD
11 thru 20:	the evaporation temperature, R.	TEVP
21 thru 30:	the heat of evaporation, BTU/LB.	HLV
31 thru 40:	the boiler efficiency, decimal form.	BLREF

Data card sample on page 82.

A MOLLIER CHART FOR STEAM

Modified and greatly reduced from Keenan and Keye's Thermodynamic Properties of Steam, published (1936) by John Wiley and Sons, Inc. Reproduced by permission of the publishers.

Abs. press., in. Hg.	Sat. temp., °F	Abs. press., lb. per sq. in.	Sat. temp., °F	Abs. press., lb. per sq. in.	Sat. temp., °F
0.20	34.56	1.0	101.74	120	341.25
0.25	40.23	2	126.08	140	353.02
0.30	44.96	3	141.48	160	363.53
0.35	49.06	4	152.97	180	373.06
0.40	52.64	5	162.24	200	381.79
0.45	55.87	6	170.06	220	389.86
0.50	58.80	7	176.85	240	397.37
0.55	61.46	8	182.86	260	404.42
0.60	63.79	9	188.28	280	411.05
0.65	66.28	10	193.21	300	417.33
0.70	68.46	12	201.96	400	444.59
0.75	70.43	14	209.56	500	467.01
0.80	72.32	14.696	212.00	600	486.21
0.85	74.13	16	216.32	700	503.10
0.90	75.84	18	222.41	800	518.23
0.95	77.47	20	227.96	1000	544.61
1.00	79.03	25	240.07	1200	567.22
1.10	81.95	30	250.33	1400	587.10
1.20	84.65	35	259.28	1600	604.90
1.30	87.17	40	267.25	1800	621.02
1.40	89.54	45	274.44	2000	635.80
1.50	91.72	50	281.01	2200	649.45
1.60	93.79	60	292.71	2400	662.11
1.70	95.77	70	302.92	2600	673.91
1.80	97.65	80	312.03	2800	684.96
1.90	99.43	90	320.27	3000	695.33
2.00	101.14	100	327.81	3206.2	705.40



Enthalpy-entropy diagram for steam.

ENTER IN CARD 4:	VARIABLE NAME
Column 1: the total number of gas turbines.	NUMGT
Column 2: the total number of diesel engines.	NUMDSL
Column 3: the total number of auto extraction steam turbines.	NUMSTT
Column 4: the total number of back pressure steam turbines.	NUBPST

Enter Ø or a combination of these four, but no more than a total of five.

Data card sample on page 83.

ENTER IN CARD 5:

Columns 1 thru 6: The decimal form of the ambient pressure at the location of this study.

NOTE: If you cannot determine the ambient pressure, use 14.7.

Variable name: PAMB
Data card sample on page 83.

To determine the maximum and minimum temperature of each month refer to the Local Climatological Data Annual Summary with Comparative Data produced by the Department of Commerce. Use the table, "Normals, Means and Extremes." A copy of this summary can be obtained from:

Climatologigal Analysis
National Climatic Center
Asheville, North Carolina 28801
FTS Telephone Number: 672-0319

Refer to pages 6 thru 9 for a copy of a sample summary.

Local Climatological Data

Annual Summary With Comparative Data

1978

PROVIDENCE, RHODE ISLAND

Narrative Climatological Summary

The proximity to Narragansett Bay and the Atlantic Ocean plays an important part in determining the climate for Providence and vicinity. In winter, the temperatures are modified considerably, and a good many of the major storms drop their precipitation in the form of rain, rather than snow. In summer, many days that would otherwise be uncomfortably warm are cooled by refreshing seabreezes. At other times of the year, sea fog may be advected in over land by onshore winds. In fact, most cases of dense fog are produced in this way; but the number of such days is few, averaging two or three days per month. In early fall, severe coastal storms of tropical origin sometimes bring destructive winds to this area. Even at other times of the year, it is usually coastal storms which produce the most severe kind of weather.

The temperature for the entire year averages around 50°, ranging from a low of 47° in 1917 to a high of 54° in 1949. January and February are the coldest months, with a mean temperature near 29°, while July is the hottest with a mean close to 72°. The average temperature for the first two months has ranged from as low as 17° in February of 1934 to as high as 39° in January of 1932; while the range for July has been from 68° in 1914 to 78° in 1952. August is nearly as warm as July, with an average temperature around 70°.

Freezing temperatures occur on the average about 125 days per year. They become a common daily occurrence the latter part of November, and cease to be common near the end of March. The average date for the last freeze in spring is April 14, while the average date for the first in fall is October 26, making the growing season about 195 days in length. Subzero weather in winter seldom occurs, averaging less than one day for December and one or two days each for January and February. The lowest temperature ever recorded in Providence has been 17° below zero (February 9, 1934).

Seventy-degree temperatures become common near the end of May, and usually cease the latter part of September. During this period, there may be several days with 90° and over, averaging near eight days per year. However, 90° temperatures have been recorded as early as March 29 (1945), and as late as October 10 (1949). Readings of 100° and over do not occur very often, and have been confined to the months of June, July and August. Some of the hottest days of summer come in August; the all-time high was 104° on August 2, 1975.

Measurable precipitation occurs on about one day out of every three, and is fairly evenly distributed throughout the year. The annual average is a little more than 42 inches, but this has varied from as little as 25.44 inches in 1965 to as much as 65.06 inches in 1972. The driest month of record was June 1949, with only 0.04 inches, while the wettest was August 1946, with 12.24 inches. There is usually no definite "dry season" but occasionally rather serious droughts are experienced; for example, the summer of 1949, when only 1 inch of rain fell during the months of June and July.

Thunderstorms are responsible for much of the rainfall from May through August. They usually produce heavy, and sometimes even excessive, amounts of rainfall; but since their duration is relatively short, damage is ordinarily light. The thunderstorms of summer are frequently accompanied by extremely gusty winds, which may result in some damage to property, especially small pleasure and fishing craft.

The first measurable snowfall of winter usually comes toward the end of November, and the last in spring is about the middle of March. The average snowfall for a winter season is close to 40 inches, ranging from as low as 11.3 inches in 1972-73 to as high as 75.6 inches in 1947-48. Only nine winters have had over 50 inches of snow, while 19 have had less than 25 inches. The month of greatest snowfall is usually February, but January and March are close seconds, with the record snowfall for any month being 31.9 inches in January 1948. It is unusual for the ground to remain well covered with snow for any long period of time. However, during the winter of 1947-48, there was a consistent snow cover from December 23 to March 18.

noaa NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION / ENVIRONMENTAL DATA AND INFORMATION SERVICE / NATIONAL CLIMATIC CENTER ASHEVILLE, N.C.

Meteorological Data For The Current Year

Station: PROVIDENCE, RHODE ISLAND # 14765 | THEO FRANCIS GREEN STATE AP | Standard time used: EASTERN | Latitude: 41° 44' N | Longitude: 71° 26' W | Elevation (ground): 51 feet | Year: 1978

Month	Temp. °F Averages: Daily maximum	Daily minimum	Monthly	Extremes: Highest	Date	Lowest	Date	Degree days Base 65°F: Heating	Cooling	Precip. Water equivalent: Total	Greatest in 24 hrs.	Date	Snow, Ice pellets: Total	Greatest in 24 hrs.	Date	Rel. humidity pct. 01	07	13	19 (Local time)
JAN	33.1	17.1	25.1	54	9	7	11	1231	0	9.01	2.33	13-14	20.9	10.0	19-20	73	77	60	71
FEB	30.7	13.4	22.1	50	23	0	11	1192	0	3.20	3.14	6-7	28.5	17.4	6-7	70	73	58	61
MAR	42.3	25.7	33.8	61	23	9	3	964	0	3.10	1.42	26-27	13.9	9.8	16-17	71	74	49	64
APR	55.9	37.4	46.7	78	28	26	3	542	0	2.33	2.04	19-20	T	T	3	66	66	41	51
MAY	67.1	46.5	57.0	87	30	30	1	250	25	5.27	1.80	24-25	0.0	0.0		79	73	56	65
JUN	76.0	57.9	66.0	90	28	40	15	26	120	1.67	0.90	21-22	0.0	0.0		77	70	49	59
JUL	80.9	62.9	71.7	97	23	51	2	0	220	4.03	1.70	3-4	0.0	0.0		78	73	53	63
AUG	78.7	63.9	71.3	90	17	55	25	0	211	6.46	2.90	6-7	0.0	0.0		87	83	63	77
SEP	69.8	49.2	59.5	87	21	37	30	180	24	1.87	0.70	18-19	0.0	0.0		86	83	54	73
OCT	61.4	41.9	51.5	78	23	28	31	412	0	3.47	1.03	14	0.0	0.0		80	83	55	75
NOV	50.7	33.9	42.3	69	10	18	27	673	0	2.01	1.01	17-18	2.5	1.2	27	81	83	64	76
DEC	41.0	26.0	33.6	62	4	14	22	970	0	5.19	1.00	25	1.4	1.3	3	75	77	55	66
YEAR	57.0	39.6	48.0	97	JUL 23	0	FEB 11	6444	610	47.01	3.14	FEB 6-7	69.7	27.0	FEB 6-7	78	77	55	67

Month	Wind: Resultant direction	Resultant speed m.p.h.	Average speed m.p.h.	Fastest mile: Speed m.p.h.	Direction	Date	Percent of possible sunshine	Average sky cover tenths, sunrise to sunset	Number of days, Sunrise to sunset: Clear	Partly cloudy	Cloudy	Precipitation .01 inch or more	Snow, Ice pellets 1.0 inch or more	Thunderstorms	Heavy fog, visibility 1/4 mile or less	Temp. °F Maximum: 90° and above (b)	32° and below	Minimum: 32° and below	0° and below	Average station pressure mb. Elev. 62 feet m.s.l.
JAN	29	6.7	11.8	46	29	20	53	6.9	9	8	14	19	5	0	4	0	17	31	0	1012.0
FEB	31	6.0	9.0	39	05	6	73	5.3	12	9	7	3	2	0	4	0	17	28	1	1012.9
MAR	29	4.7	11.0	31	20	27	71	5.9	10	7	14	10	3	0	1	0	6	22	0	1014.2
APR	30	4.6	11.9	33	29	7	66	6.0	9	9	12	10	0	0	2	0	0	6	0	1010.5
MAY	16	5.3	10.6	28	03	16	54	6.7	6	11	14	9	0	1	5	0	0	1	0	1013.5
JUN	24	4.6	10.3	23	30	16	74	6.0	12	10	8	10	0	1	2	1	0	0	0	1013.5
JUL	27	3.2	10.0	23	01	9	60	5.6	11	11	9	6	0	4	1	4	0	0	0	1013.9
AUG	24	1.0	9.2	21	35	4	50	7.2	5	9	17	13	0	6	2	0	0	0	0	1010.3
SEP	29	1.7	9.2	24	34	20	74	4.8	14	8	8	6	0	3	0	0	0	0	0	1016.0
OCT	27	3.3	9.2	26	29	24	70	4.6	15	7	9	8	0	2	1	0	0	4	0	1016.4
NOV	34	3.5	9.4	24	21	14	50	6.3	9	5	16	10	1	0	2	0	2	13	0	1019.6
DEC	29	6.8	10.7	32	30	10	47	5.7	11	7	13	10	1	0	1	0	4	27	0	1012.9
YEAR	29	3.2	10.1	46	29	JAN 20	63	5.7	123	101	141	111	12	17	19	5	46	130	2	1014.5

Normals, Means, And Extremes

Month	Temp. °F Normal: Daily maximum	Daily minimum	Monthly	Extremes: Record highest	Year	Record lowest	Year	Normal Degree days Base 65°F: Heating	Cooling	Precip. Water equivalent: Normal	Maximum monthly	Year	Minimum monthly	Year	Maximum in 24 hrs.	Year	Snow, Ice pellets: Maximum monthly	Year	Maximum in 24 hrs.	Year
(a)				25		25					25		25		25		25		25	
J	36.4	20.0	28.4	66	1974	-13	1970	1135	0	3.52	9.01	1978	0.30	1970	3.34	1962	28.7	1962	14.6	1978
F	37.6	21.2	29.4	69	1976	-6	1961	997	0	3.55	5.61	1966	1.31	1968	3.14	1978	30.9	1962	27.0	1978
M	44.7	29.3	36.9	79	1977	1	1967	871	0	3.99	7.83	1968	1.72	1963	4.53	1968	31.1	1956	16.9	1960
A	56.7	37.8	47.3	98	1976	14	1964	531	0	3.72	7.37	1961	1.40	1966	2.82	1976	3.7	1956	3.7	1957
M	68.0	46.7	56.9	94	1964	29	1956	270	0	3.40	7.27	1954	0.71	1964	3.70	1967	7.0	1977	7.0	1977
J	76.8	56.5	66.6	98	1973	41	1967	36	70	2.65	6.81	1974	0.39	1957	2.69	1972	0.0		0.0	
J	81.6	62.9	72.1	102	1977	49	1965	0	226	2.89	8.00	1970	1.08	1970	4.05	1970	0.0		0.0	
A	79.8	61.0	70.4	104	1975	40	1965	10	177	3.93	11.12	1955	0.91	1950	3.47	1955	0.0		0.0	
S	73.1	54.0	63.6	93	1960	32	1976	93	43	3.26	7.02	1961	0.77	1959	4.09	1961	0.0		0.0	
O	63.9	43.6	53.7	83	1963	20	1976	356	0	3.27	11.09	1962	1.03	1969	3.03	1962	1.5	1962	1.5	1962
N	52.4	35.0	43.8	78	1974	19	1972	651	0	4.32	8.45	1974	0.81	1970	3.13	1973	3.0	1953	3.0	1953
D	39.6	23.0	31.3	69	1969	-5	1962	1030	0	4.13	10.75	1969	0.50	1955	3.09	1969	19.0	1963	11.2	1960
YR	59.4	40.9	50.0	104	AUG 1975	-13	JAN 1970	5972	552	42.75	11.09	OCT 1962	0.39	JUN 1957	4.05	OCT 1962	31.1	MAR 1956	27.0	FEB 1978

Month	Rel. humidity pct. 01	07	13	19 (Local time)	Wind: Mean speed m.p.h.	Prevailing direction	Fastest mile: Speed m.p.h.	Direction	Year	Pct. of possible sunshine	Mean sky cover tenths, sunrise to sunset	Mean number of days, Sunrise to sunset: Clear	Partly cloudy	Cloudy	Precipitation .01 inch or more	Snow, Ice pellets 1.0 inch or more	Thunderstorms	Heavy fog, visibility 1/4 mile or less	Temp. °F Max.: 90° and above (b)	32° and below	Min.: 32° and below	0° and below	Average station pressure mb. Elev. 62 feet m.s.l.
(a)	13	13	13	13	40	10	25	25		25	29	25	25	25	25	25	29	29	13	13	13	13	6
J	70	71	57	66	11.5	NW	46	20	1978	57	6.1	10	7	14	11	3	0	2	0	17	29	2	1013.0
F	68	71	55	61	11.7	[illegible]	46	10	1972	57	6.0	8	7	13	10	3	0	2	0	9	25	1	1013.1
M	69	72	56	61	12.3	[illegible]	60	10	1950	56	6.4	9	7	15	12	2	1	2	0	2	21	0	1011.1
A	69	67	49	57	12.3	SW	51	20	1950	55	6.4	8	9	13	11	0	1	2	0	0	7	0	1011.4
M	76	71	53	62	11.0	S	42	20	1950	57	6.4	7	10	14	11	0	2	2	0	0	0	0	1012.5
J	82	76	57	67	10.0	SW	40	20	1957	56	6.1	7	10	13	11	0	4	2	2	0	0	0	1013.2
J	82	77	56	67	9.3	SW	33	30	1964	60	6.3	7	12	12	9	0	5	2	3	0	0	0	1012.9
A	83	81	55	76	9.3	SSW	90	11	1954	59	6.1	9	10	12	10	0	4	1	2	0	0	0	1013.5
S	86	85	57	76	9.5	SW	90	10	1960	59	5.6	10	8	12	8	0	2	2	1	0	0	0	1015.5
O	80	83	56	77	9.7	[illegible]	41	19	1954	60	5.4	11	9	12	8	0	1	3	0	0	0	0	1016.1
N	76	78	58	70	10.5	SW	52	10	1957	49	6.5	8	7	15	11	0	1	2	0	0	13	0	1015.1
D	74	70	58	69	11.0	[illegible]	60	14	1957	52	6.2	9	7	15	12	2	0	1	0	6	23	0	1014.2
YR	76	75	55	66	10.7	SW	90	11	AUG 1954	57	6.1	103	102	160	124	10	20	25	8	28	123	7	1013.0

Means and extremes above are from existing and comparable exposures. Annual extremes have been exceeded at other sites in the locality as follows: Lowest temperature -17 in February 1934; maximum monthly precipitation 12.24 in August 1946; minimum monthly precipitation .04 in June 1949; maximum monthly snowfall 31.9 in January 1948; fastest mile wind 95 NE in September 1938.

(a) Length of record, years, through the current year unless otherwise noted, based on January data.
(b) 70° and above at Alaskan stations.
* Less than one half.
T Trace.

NORMALS - Based on record for the 1941-1970 period.
DATE OF AN EXTREME - The most recent in cases of multiple occurrence.
PREVAILING WIND DIRECTION - Record through 1963.
WIND DIRECTION - Numerals indicate tens of degrees clockwise from true north. 00 indicates calm.
FASTEST MILE WIND - Speed is fastest observed 1-minute value when the direction is in tens of degrees.

Average Temperature

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual
1939	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1940	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1941	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1942	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1943	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1944	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1945	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1946	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1947	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1948	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1949	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1950	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1951	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1952	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1953	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1954	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1955	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1956	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1957	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1958	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1959	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1960	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1961	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1962	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1963	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1964	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1965	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1966	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1967	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1968	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1969	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1970	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1971	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1972	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1973	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1974	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1975	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1976	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1977	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1978	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RECORD MEAN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MAX	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MIN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Heading Degree Days

Season	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	Total
1938-39	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1939-40	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1940-41	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1941-42	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1942-43	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1943-44	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1944-45	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1945-46	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1946-47	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1947-48	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1948-49	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1949-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1950-51	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1951-52	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1952-53	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1953-54	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1954-55	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1955-56	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1956-57	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1957-58	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1958-59	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1959-60	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1960-61	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1961-62	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1962-63	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1963-64	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1964-65	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1965-66	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1966-67	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1967-68	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1968-69	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1969-70	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1970-71	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1971-72	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1972-73	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1973-74	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1974-75	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1975-76	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1976-77	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1977-78	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1978-79	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Cooling Degree Days

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
1969	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1970	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1971	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1972	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1973	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1974	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1975	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1976	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1977	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1978	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Precipitation

Year	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual
1939	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1940	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1941	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1942	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1943	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1944	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1945	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1946	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1947	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1948	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1949	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1950	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1951	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1952	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1953	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1954	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1955	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1956	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1957	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1958	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1959	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1960	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1961	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1962	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1963	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1964	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1965	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1966	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1967	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1968	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1969	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1970	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1971	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1972	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1973	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1974	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1975	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1976	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1977	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1978	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RECORD MEAN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Snowfall

Season	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	Total
#1939-40	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1940-41	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1941-42	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1942-43	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1943-44	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1944-45	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1945-46	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1946-47	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1947-48	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1948-49	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1949-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1950-51	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1951-52	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
#1952-53	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1953-54	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1954-55	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1955-56	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1956-57	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1957-58	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1958-59	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1959-60	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1960-61	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1961-62	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1962-63	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1963-64	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1964-65	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1965-66	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1966-67	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1967-68	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1968-69	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1969-70	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1970-71	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1971-72	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1972-73	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1973-74	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1974-75	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1975-76	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1976-77	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1977-78	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1978-79	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
RECORD MEAN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

# Indicates a station move or relocation of instruments. See Station Location table.

Record mean values above are means through the current year for the period beginning in 1905 for temperature and precipitation, 1936 for snowfall. Data are from City Office locations through 3-20-33 except that temperatures are from the Airport 11-10-41 through 12-31-41 and precipitation is from the Airport 11-10-41 through 3-28-43.

STATION LOCATION

Location	Occupied from	Occupied to	Airline distance and direction from previous location	Latitude North	Longitude West	Elevation above Sea level: Ground at temperature site	Elevation above Ground: Wind instruments	Extreme thermometers	Psychrometer	Telepsychrometer	Tipping bucket rain gage	Weighing rain gage	8" rain gage	Hygrothermometer		Remarks
CITY																
University Hall, Brown University, Prospect St.	10/22/04	1/01/09		41° 50'	71° 24'	125	67	57	57		56		56			
Banigan Building 10 Weybosset Street	1/01/09	6/22/13	1500 ft. WSW	41° 50'	71° 25'	9	165	141	141		134		134			Winds affected by higher building to west from 1/1/13 to 6/22/13.
Turks Head Building 11 Weybosset Street	6/22/13	6/10/40	100 ft. W	41° 50'	71° 25'	8	251	215	215		211		211			Winds affected by higher building to west from 3/38/38 to 6/16/41.
Post Office Annex Bldg. Exchange Terrace (A)	6/10/40	5/20/53	600 ft. NNW	41° 50'	71° 25'	12	74	65	65		58	58	58			Wind instruments exposed on Turks Head Building until 6/16/41 at which time they were moved to P.O. Annex Building. Wind instrument exposure on P.O. Annex Building very poor. (A) - Observation program transferred to Airport Station 11/10/41, but official records resumed at City Office for temperatures 1/1/42 and for precipitation 3/1/42.
AIRPORT																
Administration Building	6/16/32	11/12/39		41° 44'	71° 26'	55	52		5							Airway Station to 9/27/37 then First-Order Weather Bureau Airport Station. All locations at the T. F. Green Airport, Hillsgrove, Rhode Island.
Hangar Building No. 1	11/12/39	5/20/53	660 ft. W	41° 44'	71° 26'	55	60	46	46		44		44			
Old Administration Bldg.	5/20/53	9/25/59	660 ft. E	41° 44'	71° 26'	55	39	7	5			4	3			
Old Administration Bldg. T. F. Green State Airport ¢	9/25/59	Present		41° 44'	71° 26'	a51	20	7	6			4	3	#6		Wind equipment relocated to field site approximately 2200 feet south of Weather Bureau office. a - 55 feet until 11/1/63. # - Commissioned 11/1/63.
¢ Name effective in December 1967																

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I certify that this is an official publication of the National Oceanic and Atmospheric Administration, and is compiled from records on file at the National Climatic Center, Asheville, North Carolina 28801.

Daniel B Mitchell
Director, National Climatic Center

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210

FIRST CLASS

ENTER IN CARD 6:

The maximum temperature of each month in R (degree Rankine form; (0°F = 459°R) is to be entered in card 6.

If you cannot obtain the previously described publication for the area of this study, assume 59°F (518°R) for all values.

Columns:	1 thru 6:	January
	7 thru 12:	February
	13 thru 18:	March
	19 thru 24:	April
	25 thru 30:	May
	31 thru 36:	June
	37 thru 42:	July
	43 thru 48:	August
	49 thru 54:	September
	55 thru 60:	October
	61 thru 66:	November
	67 thru 72:	December

Variable name: TMAX (month)
Month = 1, 12; (January thru December)
Data card sample on page 84.

ENTER IN CARD 7:

The minimum temperature of each month in R (degree Rankine form; (0°F = 459°R) is to be entered in card 7.

If you cannot obtain the previously described publication for the area of this study, assume 59°F (518°R) for all values.

Columns:	1 thru 6:	January
	7 thru 12:	February
	13 thru 18:	March
	19 thru 24:	April
	25 thru 30:	May
	31 thru 36:	June
	37 thru 42:	July
	43 thru 48:	August
	49 thru 54:	September
	55 thru 60:	October
	61 thru 66:	November
	67 thru 72:	December

Variable name: TMIN (month)
Month = 1, 12; (January thru December)
Data card sample on page 84.

If the system does not have any gas turbines, the number entered in column 1 of data card 4 is zero (Ø). Do not prepare data cards 8, 9, and 10.

Turn to page 15.

If the system has more than one gas turbine, the number entered in Column 1 of data card 4 is more than one. Prepare one set of data cards, numbers 8, 9, and 10, for each turbine. Place each set of data cards (numbers 8, 9, and 10) after each other in the data deck.

EXAMPLE: Turbine 1 data cards 8, 9, 10
Turbine 2 data cards 8, 9, 10
Turbine 3 data cards 8, 9, 10

ENTER IN CARD 8:

The design conditions for the gas turbine (refer to the table on page 12 for representative information).

			VARIABLE NAME
Columns:	1 thru 12:	the design output at full load; KW.	ED
	13 thru 24:	the design fuel consumption at full load; BTU/HR.	QFD
	25 thru 36:	the design air flow; LBS/HR.	AIRFLD
	37 thru 48:	the compressor inlet temperature; R. If not known, use 519.	TAMBD
	49 thru 60:	the compressor inlet pressure; PSIA. If not known, use 14.7.	PAMBD
	61 thru 72:	the lower heating value of the fuel used, BTU/LB. This will be approximately 18,300 to 19,800 BTU/LB for distillate oil, and 20,000 to 23,000 BTU/LB for natural gas.	HV

Data card sample on page 85.

GAS TURBINE MODEL NUMBER	OUTPUT KW COLUMNS 1-12	FUEL CONSUMPTION COLUMNS 13-24	AIRFLOW COLUMNS 25-36	STD. TEMP. COLUMNS 37-48	STANDARD PRESSURE COLUMNS 49-60*
ALLISON 501-KB	2,500	30,214,000	88,148 $\frac{LB}{HR}$	59°F	14.7 PSIA
ALLISON 570-K	4,806	58,608,000	154,080	59°F	14.7 PSIA
GARRETT 1E 831-800	515	8,700,000	28,237	59°F	14.7 PSIA
GARRETT 1E 990-51	4,103	48,070,000	138,500	59°F	14.7 PSIA
GE 5341	24,200	298,900,000	928,500	59°F	14.7 PSIA
GEG 3142	10,150	138,550,000	408,800	59°F	14.7 PSIA
GEG 5261	18,900	252,000,000	767,000	59°F	14.7 PSIA

* NOTE: For COLUMNS 61-72, the LOWER HEATING VALUE, refer to page 11.

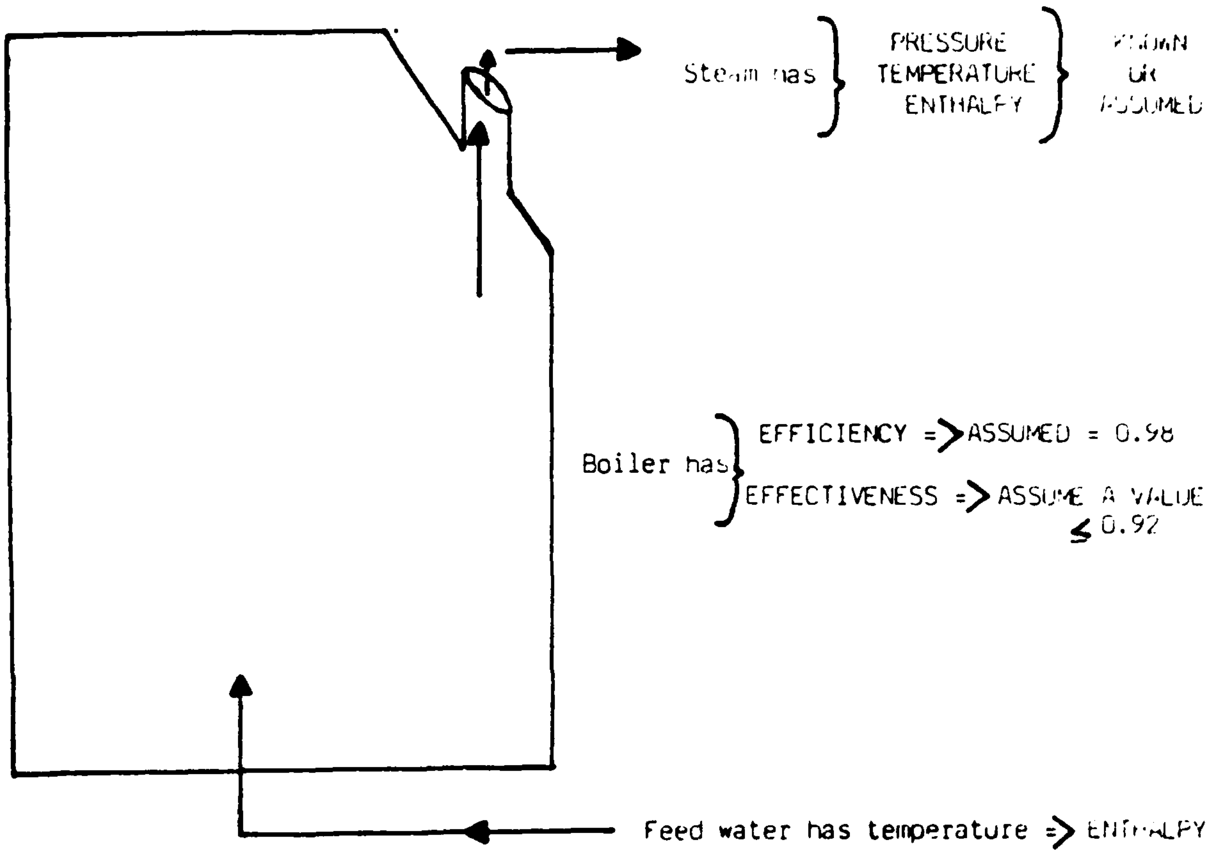
ENTER IN CARD 9:

The "off-design" conditions for the gas turbine.

Use input information at a given partial load (say 1/2 load) in order to formulate the performance curves. If this information is not known, input zeros (Ø) for all. The calculation will be based on the already built-in performance curves.

Columns			VARIABLE NAME
Columns:	1 thru 12:	the power output at the above given partial load; KW.	EDP
	13 thru 24:	the fuel consumption at the above given partial load; BTU/HR.	QFP
	25 thru 36:	the fuel consumption at the zero load (no power) condition; BTU/HR. If not known, input the value of 0.315 of design fuel consumption at full load, BTU/HR.	QFO
	37 thru 48:	the turbine exhaust gas temperature at full load, R.	TEXHD
	49 thru 60:	the turbine exhaust gas temperature at the above given partial load.	TEXHP
	61 thru 72:	the stack temperature, R. This will be normally about 50°F to 75°F higher temperature of the steam and with a low limit of 250°F to 300°F.	TSTACK

Data card sample on page 85.



THE HEAT RECOVERY BOILER

ENTER IN CARD 10:

Columns:		VARIABLE NAME
1 thru 10:	the steam pressure, PSIG.	STMPRE
11 thru 20:	the steam temperature, R.	STMTEP
21 thru 30:	the enthalpy of steam, BTU/LB.	STMENTH
31 thru 40:	the temperature of the feed water, R.	FETEMP
41 thru 50:	the enthalpy of the feed water, BTU/LB.	FEENTH
51 thru 60:	accounts for "radiation" losses from the waste heat recovery boiler. This is normally about 0.98 (decimal form).	EFFCTV
61 thru 70:	the effectiveness of the waste heat recovery boiler (decimal form).	EFFNS

Data card sample on page 86.

If the system does not have any diesel engines, the number entered in column 2 of data card 4 is zero (Ø). Do not prepare data cards 11 and 12. Turn to page 22.

If the system has more than one diesel engine, the number entered in column 2 of data card 4 is more than one. Prepare one set of data cards (numbers 11 and 12) for each engine. Place each set of data cards, (numbers 11 and 12) after each other in the data deck.

EXAMPLE: Engine 1 data cards 11 and 12
Engine 2 data cards 11 and 12
Engine 3 data cards 11 and 12

ENTER IN CARD 11:

For specific information refer to the manufacturer's data sheet. A similar data sheet is shown on pages 16 thru 21.

			VARIABLE NAME
Columns:	1 thru 12:	the net engine output at full load; KW (#1 on example data sheet).	ED
	13 thru 24:	the fuel consumption at full load; BTU/HR.	QFD
	25 thru 36:	the exhaust gas temperature at full load; R (#2 on example data sheet).	TEXHD
	37 thru 48:	the exhaust gas temperature at a partial load; R. If not known, input zero.	TEXHP
	49 thru 60:	the power output at the above partial load; KW. If the exhaust gas temperature is input zero, input zero for this also.	EDP

Data card sample on page 87.

ENTER IN CARD 12:

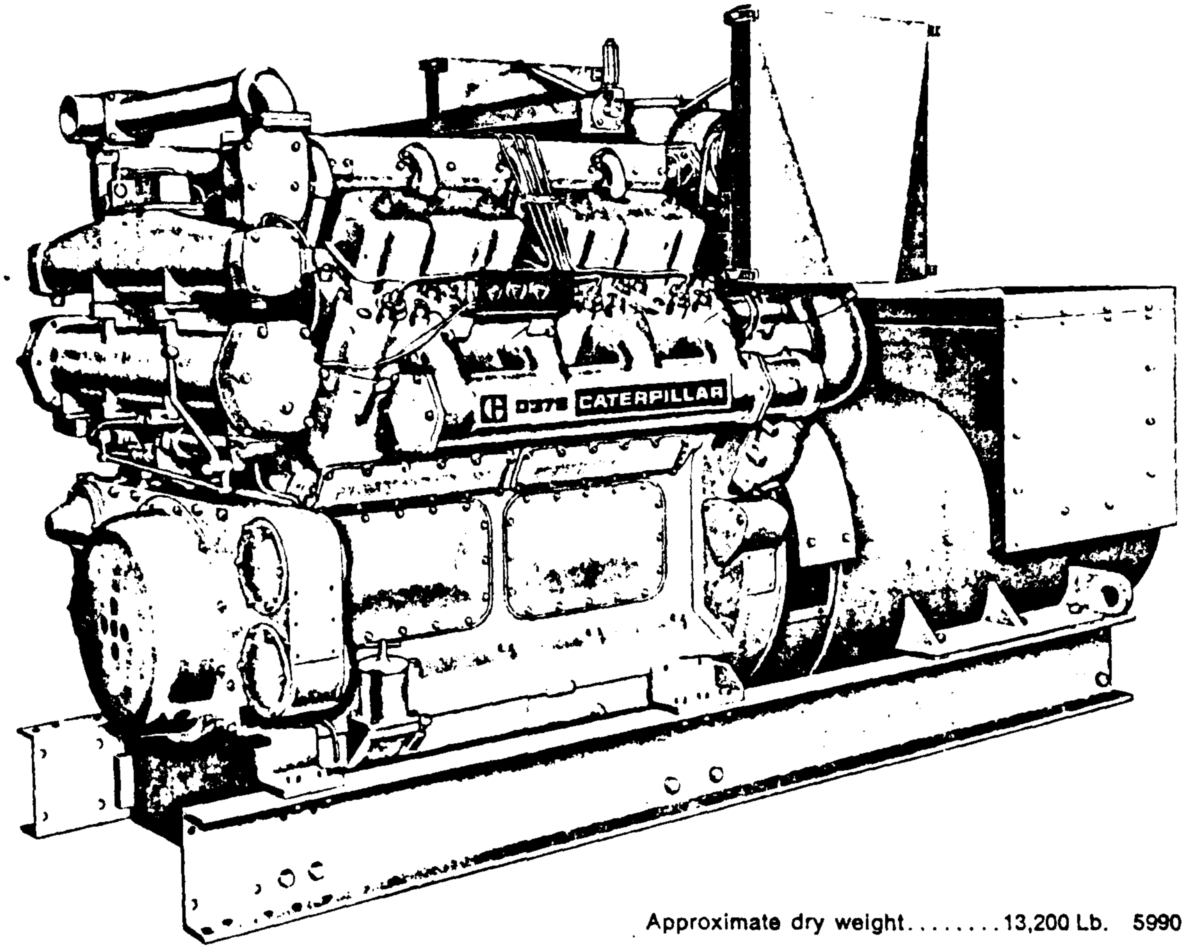
Data on the exhaust heat recovery boiler for the diesel engine.

			VARIABLE NAME
Columns:	1 thru 10:	the intake air flow; LB/HR (#3 on the example data sheet	AIRFLD
	11 thru 20:	the stack temperature of gases leaving the boiler, R. This will be normally about 50°F to 75°F higher than the temperature of steam and with a lower limit of 710°R to 760°R.	TSTACK
	21 thru 30:	the steam pressure; PSIG.	STMPRE
	31 thru 40:	the steam temperature; R.	STMTEP
	41 thru 50:	the enthalpy of steam; BTU/LB.	STMENTH
	51 thru 60:	the temperature of the feed water; R.	FETEMP
	61 thru 70:	the enthalpy of the feed water; BTU/LB.	FEENTH
	71 thru 80:	accounts for "radiation" losses from the the exhaust heat recovery boiler, normally about 0.98 (decimal form).	EFFCTV

Data card sample on page 87.

CATERPILLAR

D379B PRIME POWER ELECTRIC SET



Approximate dry weight........13,200 Lb. 5990 Kg.

PRIME POWER RATINGS

	60 Hz @ 1200 RPM Jacket Water Aftercooler	50 Hz @ 1000 RPM Jacket Water Aftercooler
KW @ 0.8 P.F. (w/o fan)...	400	330
KVA....................	500	412.5
Voltages Available.........	125/216 230-460 2400	200-400 230-460 —
Phase....................	3	3
Wire & Connection........	10, Wye	10, Wye

DIESEL ENGINE

Four stroke cycle turbocharged—aftercooled diesel engine.

Number of cylinders.......................... V-8

Bore and stroke: inches ....6.25 x 8.00
millimeters ....159 x 203

Piston displacement: cu. in. 1964
liters 32,2

Compression ratio 15.5:1

Full load speed....................60 Hz 1200 RPM
50 Hz 1000 RPM

STANDARD EQUIPMENT

Dry, Single-Stage Air Cleaners

Flexible Fuel Lines

Fuel Filters

Fuel Priming and Transfer Pumps

Woodward UG8 Governor (Isochronous Regulation)

Gear-Driven Jacket Water Pump

Water Temperature Gauge

Thermostats and Housing

Lube Oil Cooler and Filters

Lube Oil and Fuel Pressure Gauges

Tachometer Drive (SAE Standard)

Safety Shutoffs for Low Oil Pressure and Overspeed

Mounting Rails

Service Meter

Dry, Water-Shielded Exhaust Manifolds

Lifting Eyes

Oil Pan (23° approx. max. tilt angle)

ATTACHMENTS

- ☐ Air Cleaner Service Indicator
- ☐ Alarm Switch
- ☐ Automatic Transfer Switch
- ☐ Auxiliary Drives
- ☐ Auxiliary Water Pump (Standard on Raw Water Aftercooled Engine)
- ☐ Charging Alternator
- ☐ Cooling Systems—Radiator, Heat Exchanger, Ebullient
- ☐ Exhaust Fittings
- ☐ Expansion Tank
- ☐ Glow Plugs
- ☐ Mufflers
- ☐ Precleaner
- ☐ Starting Systems—Air, Hydraulic, 30-32 Volt Electric
- ☐ Tachometer
- ☐ Wall-Mounted Control Panel
- ☐ Watercooled Exhaust Manifolds
- ☐
- ☐
- ☐
- ☐
- ☐
- ☐
- ☐
- ☐
- ☐

Additional attachments are available. Consult your Caterpillar representative for specific requirements.

SRCR GENERATOR

Construction:
Revolving-field, single bearing AC generator with built-in, statically-regulated, statically-excited system. Amortisseur windings function to oppose pulsation of the magnetic field, minimizing the hunting effect when generators are paralleled.

Excitation:
By rectified alternating current. Voltage buildup relay only moving part.

Regulation:
Silicon controlled rectifier. Transistorized voltage regulator, with no moving parts, automatically maintains voltage within ±2% from no load to full load. No external voltage regulator needed.

Insulation:
High temperature Class F insulation in stator and rotor.

Parallel Operation:
Cross current compensation standard.

Coupling:
Close-coupled, steel disc type.

Voltage Level:
Terminal voltage adjustable within ±5% of rated voltage (except 50 Hz 230-460 V, which is adjustable within +10% to −5%).

Voltage Droop:
Adjustable for proper division of reactive KVA when operating in parallel with other alternators.

Voltage Gain:
Adjustable to compensate for engine speed variation when operating with a speed droop governor.

RATINGS:

Prime Power — For continuous service with normally varying loads.

Maximum Power—Horsepower capability which can be demonstrated within 5% at the factory.

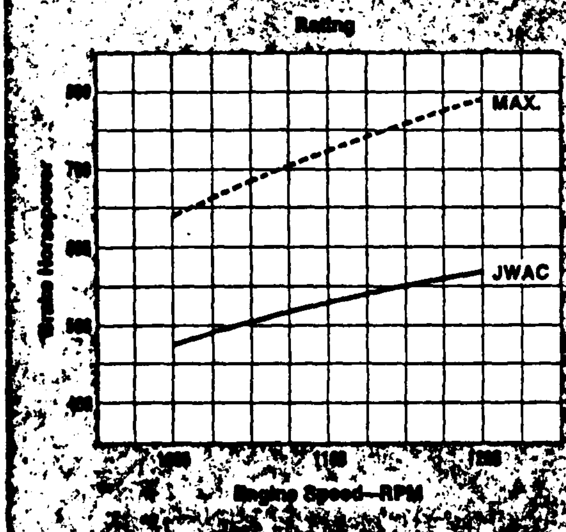
STANDARDS:

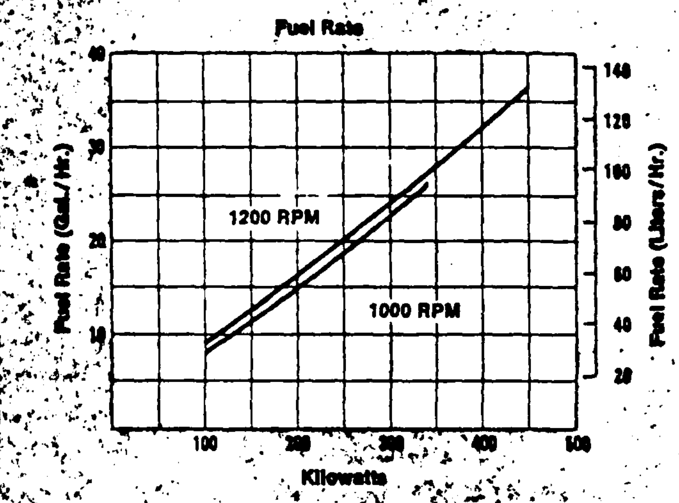
Ratings based on SAE standard conditions of 29.38 in. (746 mm) of mercury and 85°F (29°C).

ALTITUDE AND TEMPERATURE CAPABILITIES

60 Hz 1200 RPM	50 Hz 1000 RPM
3000 ft. and 80°F* (900m) (27°C)	500 ft. and 85°F† (150m) (29°C)

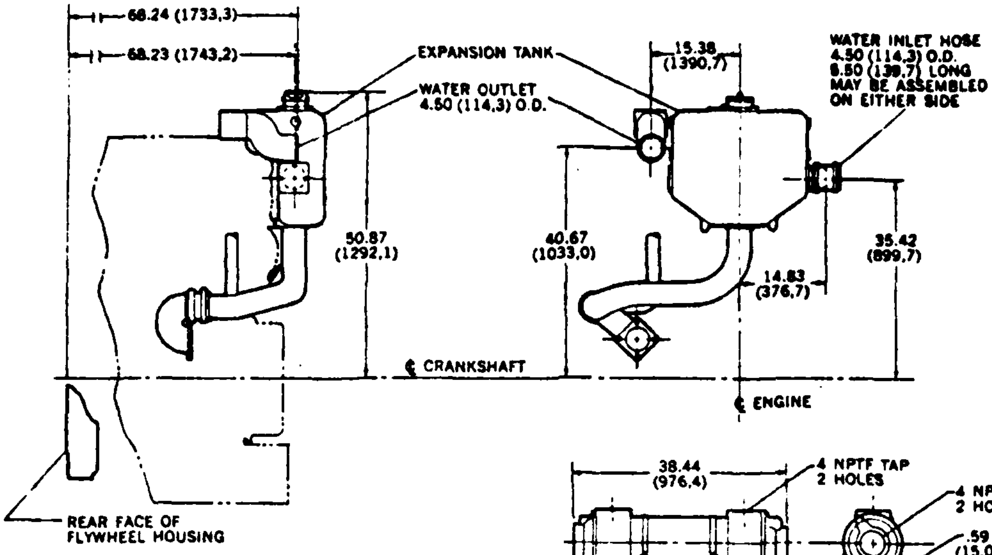
Between Operating Capability and 7000 ft. (2100m) and 60°F (16°C) derate
*3% for each 1000 ft. (300m) and 1% for each 10°F (6°C)
†6% for each 1000 ft. (300m) and 2% for each 10°F (6°C)
Above 7000 ft. and 60°F, consult your Caterpillar representative.



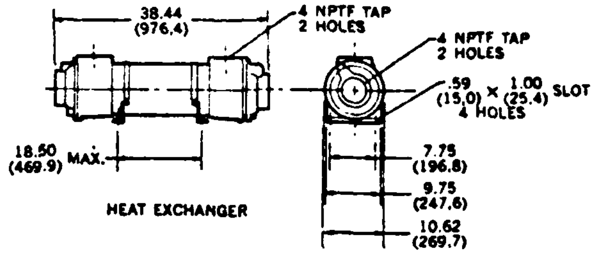


KW = BHP × 0.746 × generator efficiency.

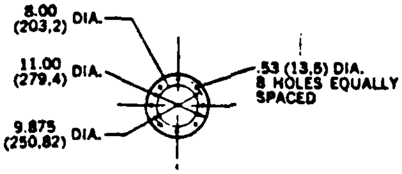
Fuel consumption applies to standard electric set engine W/O fan, based on fuel oil having a gross heat value of 19,500 BTU per pound (10,830K-cal/Kg) and weighing 7.12 pounds per U.S. gallon (855 gm/ltr).



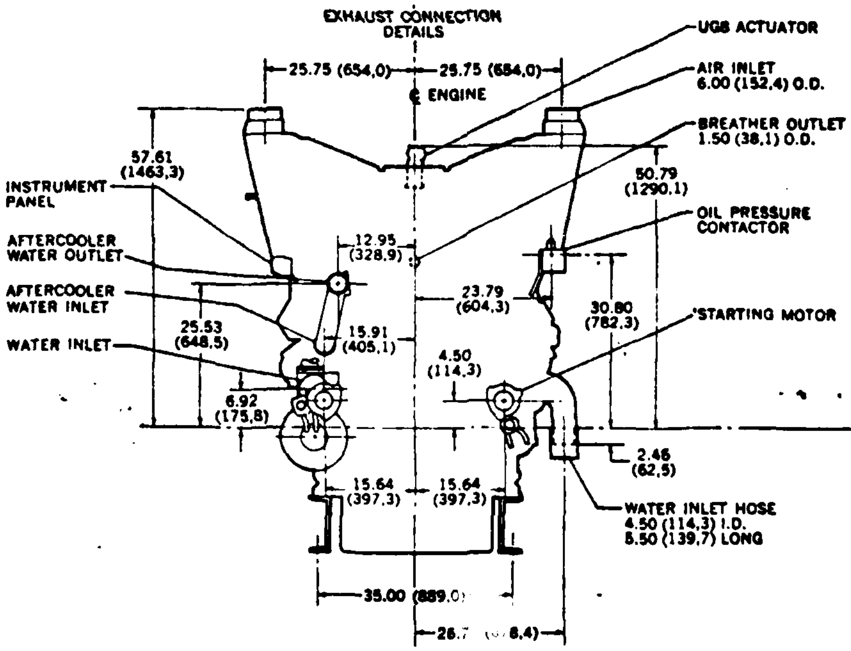
EXPANSION TANK GROUP



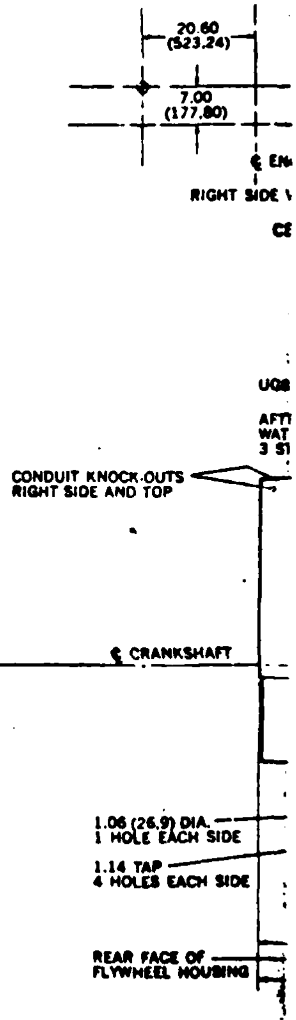
HEAT EXCHANGER

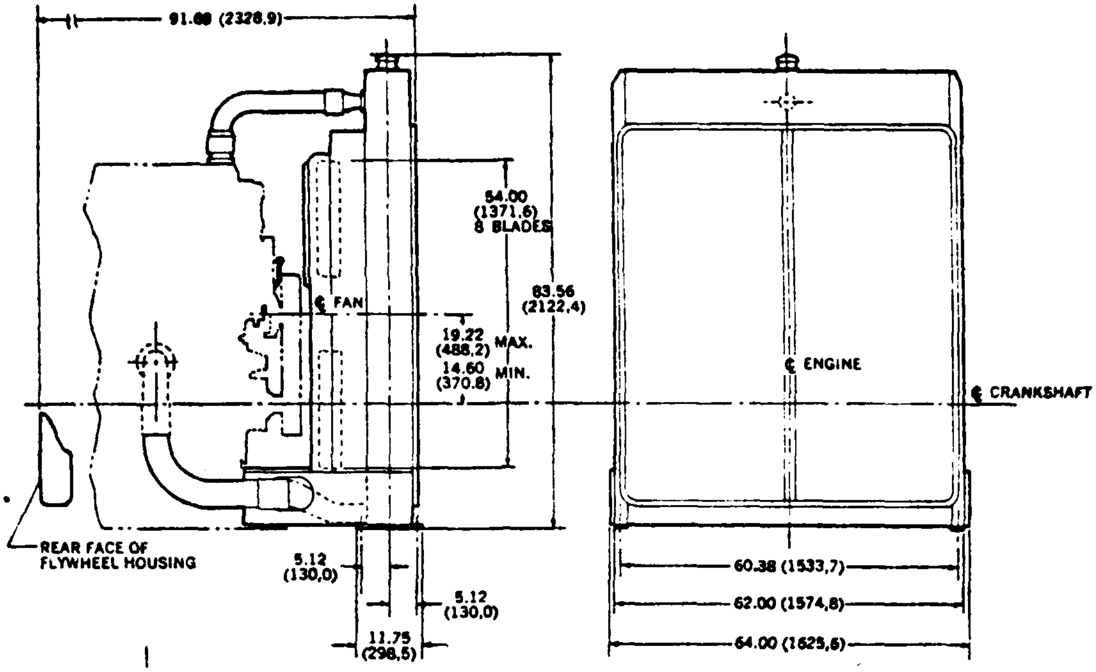


EXHAUST CONNECTION
DETAILS

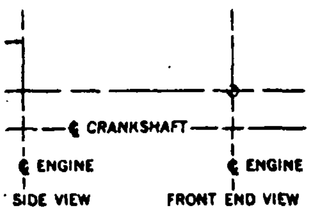


FLYWHEEL END OF ENGINE

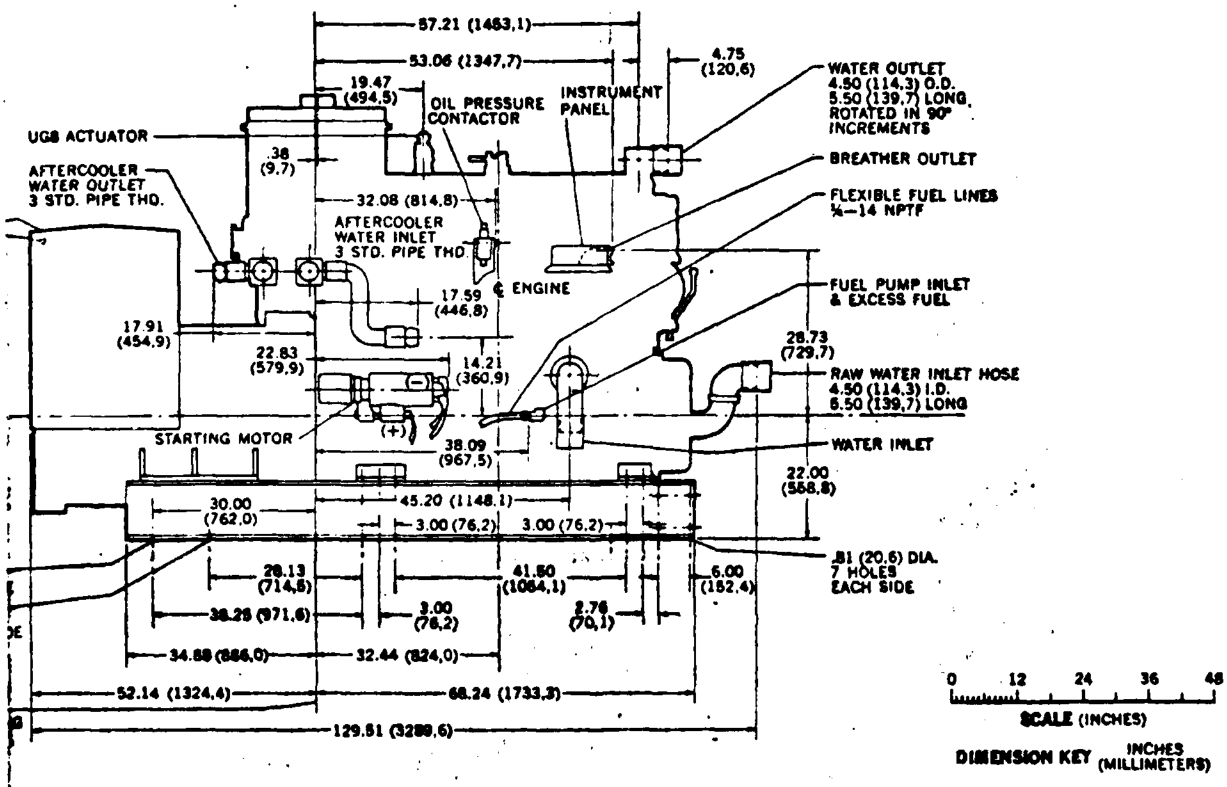




RADIATOR AND FAN DRIVE GROUP



CENTER OF GRAVITY



Installation Facts

	60 Hz 1200 RPM	50 Hz 1000 RPM
FUEL SYSTEM		
Transfer pump		
†Max. total suction head (lift and line resistance) ft · m	12 · 3.66	12 · 3.66
Cap. @ 85% eff. gpm · lit/sec	5.42 · .351	4.52 · .285
LUBRICATING SYSTEM		
Sump Capacity (Refill) gal · lit	50 · 189.3	50 · 189.3
COOLING WATER SYSTEM		
Volume gal · lit		
Engine only	40 · 151.4	40 · 151.4
Radiator for max. ambient of 125°F. · 51°C.	28 · 106	28 · 106
Water pump performance		
Jacket Water		
Capacity @ 30 ft · 9.12 m Head gpm · lit/sec	290 · 18.3	210 · 13.2
Capacity @ 5 ft · 1.52 m Head gpm · lit/sec	346 · 21.8	284 · 17.9
Max. Allowable Static Head ft · m	57.7 · 17.54	57.7 · 17.54
Auxiliary water		
Capacity @ 20 ft · 6.08 m Head gpm · lit/sec	275 · 17.3	200 · 12.6
Capacity @ 0 ft · m Head gpm · lit/sec	340 · 21.5	260 · 16.4
Max. Allowable Static Head ft · m	30 · 9.12	30 · 9.12
Pressure		
Maximum System Pressure psi [illegible] /cm²		
Water jacket	25 · 1.8	25 · 1.8
Aftercooler	40 · 2.8	40 · 2.8
Radiator	7 · .5	7 · .5
HEAT REJECTION		
To Jacket Water (Incl. standard manifolds, A/C, and oil cooler) btu/min · k cal/min	24500 · 6170	20400 · 5130
Temperature		
Max. jacket water temperature °F. · °C.	210 · 99	210 · 99
Radiator data		
Fan power HP · KW with 125°F. · 51°C. radiator	30 · 21.0	17.5 · 12.3
Air flow through 125°F. · 51°C. radiator cfm · lit/sec	38200 · 18028	31500 · 14868
Max. allowable static pressure @ exhaust side of radiator in · mm H_2O with large radiator @ 100°F. · 38°C. ambient	.5 · 12.7	.5 · 12.7
ENGINE ROOM VENTILATION REQUIREMENTS		
#3 -- Combustion Air requirements @ 85°F. · 29°C. cfm · lit/sec	1245 · 586	838 · 396
Heat radiated by engine btu/min · k cal/min	1610 · 405	1570 · 396
Heat dissipated by generator btu/min · k cal/min	1478 · 372	1365 · 344
Ventilation recommended for 15°F. · 9°C. rise (engine and generator radiated heat only) cfm · lit/sec	12150 · 5720	11600 · 5460
EXHAUST SYSTEM		
Gas Volume cfm · lit/sec	3260 · 1540	2315 · 1092
#2 - Gas Temperature °F. · °C. (Stack)	965 · 519	1045 · 564
Max. Permissible Back Pressure in · mm H_2O	20 · 508	20 · 508
STARTING SYSTEM		
Air system		
Min. air pressure required at motor psi · kg/cm²	190 · 6.33	90 · 6.33
Max. air pressure allowed at motor psi · kg/cm²	150 · 10.55	150 · 10.55
Electric dual motor system		
Voltage	32	32
Breakaway Current (Amps.)		
@ 70°F. · 21°C.	1100	1100
@ 40°F. · 04°C.	1550	1550
Rolling Current (Amps.)		
@ 70°F. · 21°C.	440	440
@ 40°F. · 04°C.	620	620

†Using .5 inches · 1.27 cm I.D. Tubing, max. length 50 ft · 15.2 m

Material and specifications subject to change without notice.

LEO 21187-01 (12-69)
SUPERSEDES LEO 21

PRINTED IN U.

If the system does not have any auto extraction steam turbines, the number entered in column 3 of data card 4 is zero (Ø). Do not prepare data cards 13, 14, 15, and 16. Turn to page 38.

If the system has more than one auto extraction steam turbine, the number entered in column 3 of data card 4 is more than one. Prepare one set of data cards, numbers 13, 14, 15, and 16, for each turbine. Place each set of data cards (numbers 13, 14, 15, and 16) after each other in the data deck.

<u>EXAMPLE</u>: Turbine 1 data cards 13, 14, 15, and 16
Turbine 2 data cards 13, 14, 15, and 16
Turbine 3 data cards 13, 14, 15 and 16

Refer to the diagrams, performance maps, steam chart, and the General Electric publication for specific information. These are located on pages 24 thru 37.

		VARIABLE NAME AND SYMBOL ON CHARTS

ENTER IN CARD 13:

Columns:		
1 thru 12:	the pressure of the throttle steam; PSIG.	PAMBD
13 thru 24:	the pressure of the extraction steam; PSIG.	WCD
25 thru 36:	the pressure of the exhausted steam; PSIG.	WTD
37 thru 48:	the temperature of the throttle steam; F.	TAMBD
49 thru 60:	the maximum generator output at a power factor of 1.00; KW.	EED
61 thru 72:	the generator rated output; KW	ED

Data card sample on page 88.

ENTER IN CARD 14:

Columns:		
1 thru 12:	a correction to the extraction factor. This will be 0.857 for a condensing turbine and 0.902 for a non-condensing turbine.	T3LIM
13 thru 24:	the enthalpy of the throttle steam.	TPNCHD
25 thru 36:	the enthalpy of the feed water to the boiler.	TEXHD
37 thru 48:	the efficiency of the boiler for the steam turbine (decimal form).	T3FRC
49 thru 60:	the percentage of extracted steam to be exported (decimal form). Accounts for steam used in plant.	EFFCTV
61 thru 72:	the maximum throttle steam flow; LBS/HR.	THROMAX

Data card sample on page 88.

ENTER IN CARD 15:

Columns:		
1 thru 12:	the maximum extraction flow; LBS/HR.	EXPD
13 thru 24:	the theoretical steam rate, from throttle to exhaust; LBS/KWH.	T2D
25 thru 36:	the theoretical steam rate, from throttle to extraction; LBS/KWH.	T3D
37 thru 48:	the half load non-extraction throttle flow factor.	WC

Data card sample on page 89.

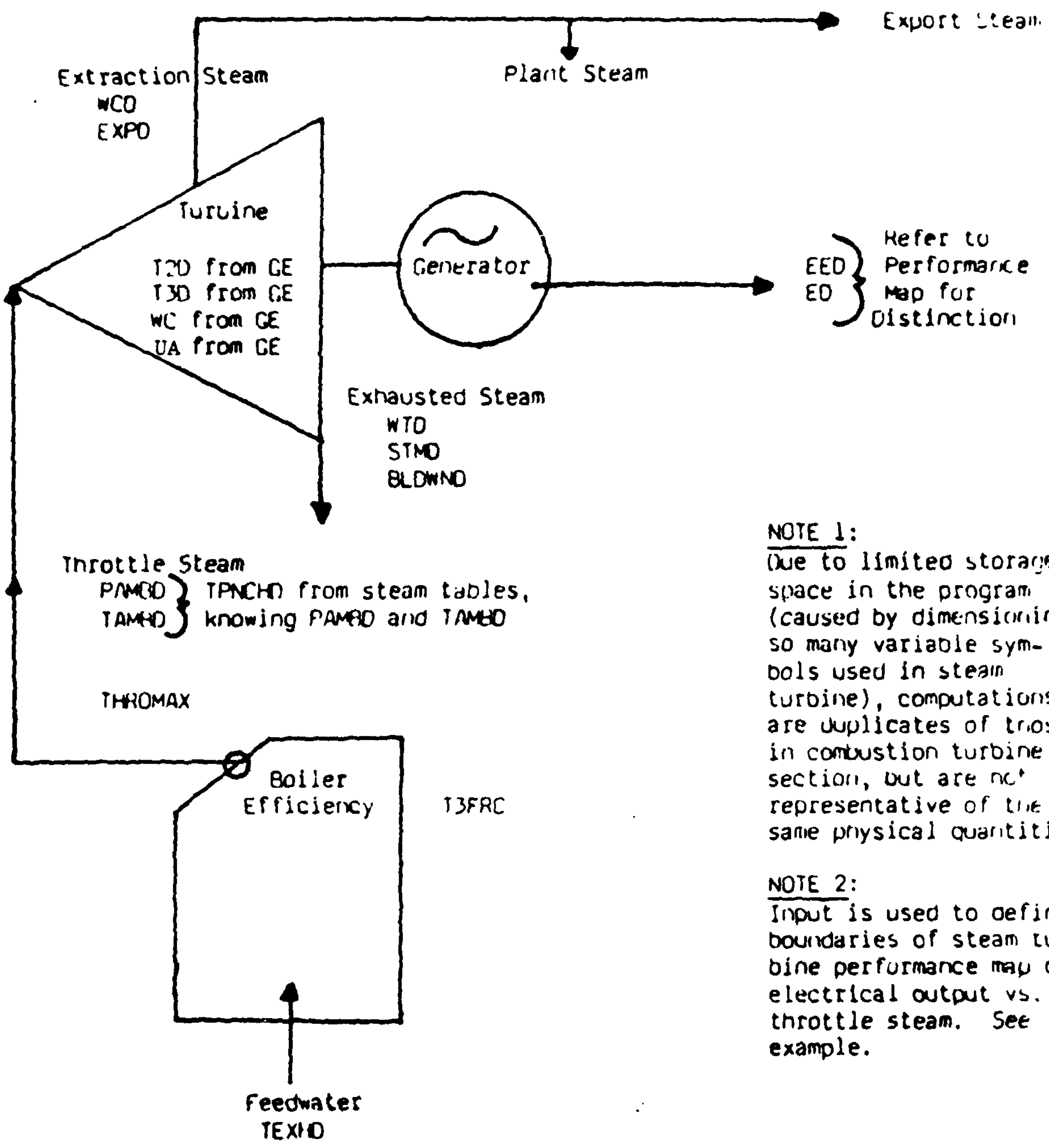
ENTER IN CARD 16:

Columns:		
1 thru 12:	the maximum exhaust flow; LBS/HR.	STMD
13 thru 24:	the minimum exhaust flow; LBS/HR.	BLDWND
25 thru 36:	the full load non-extraction efficiency of the turbine (decimal form)	UA

Data card sample on page 89.

AUTO EXTRACTION TURBINE

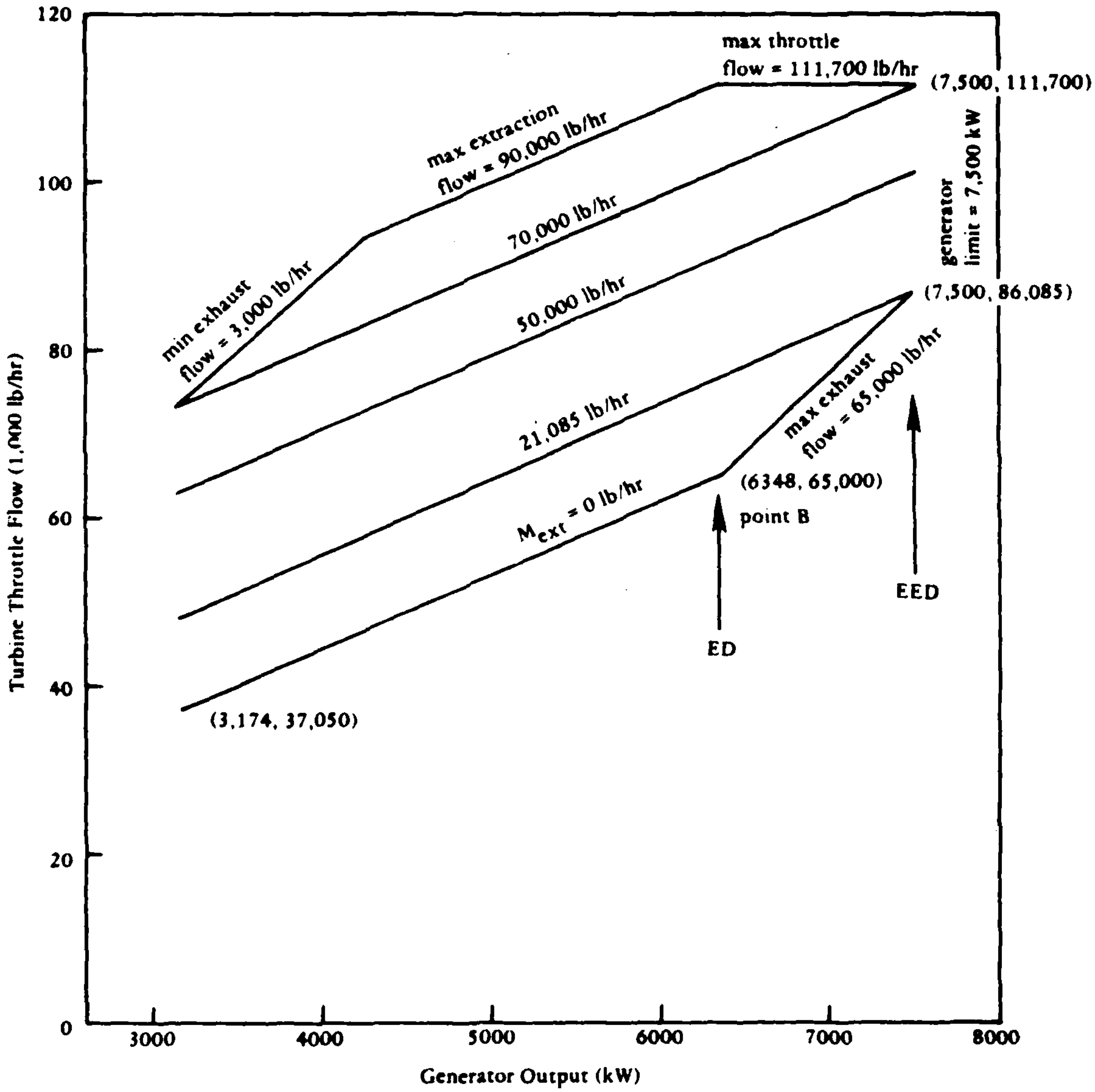
$$EFFCTV = \frac{\text{Export Steam}}{\text{Export \& Plant Steam}}$$



NOTE 1:
Due to limited storage space in the program (caused by dimensioning so many variable symbols used in steam turbine), computations are duplicates of those in combustion turbine section, but are not representative of the same physical quantities.

NOTE 2:
Input is used to define boundaries of steam turbine performance map of electrical output vs. throttle steam. See example.

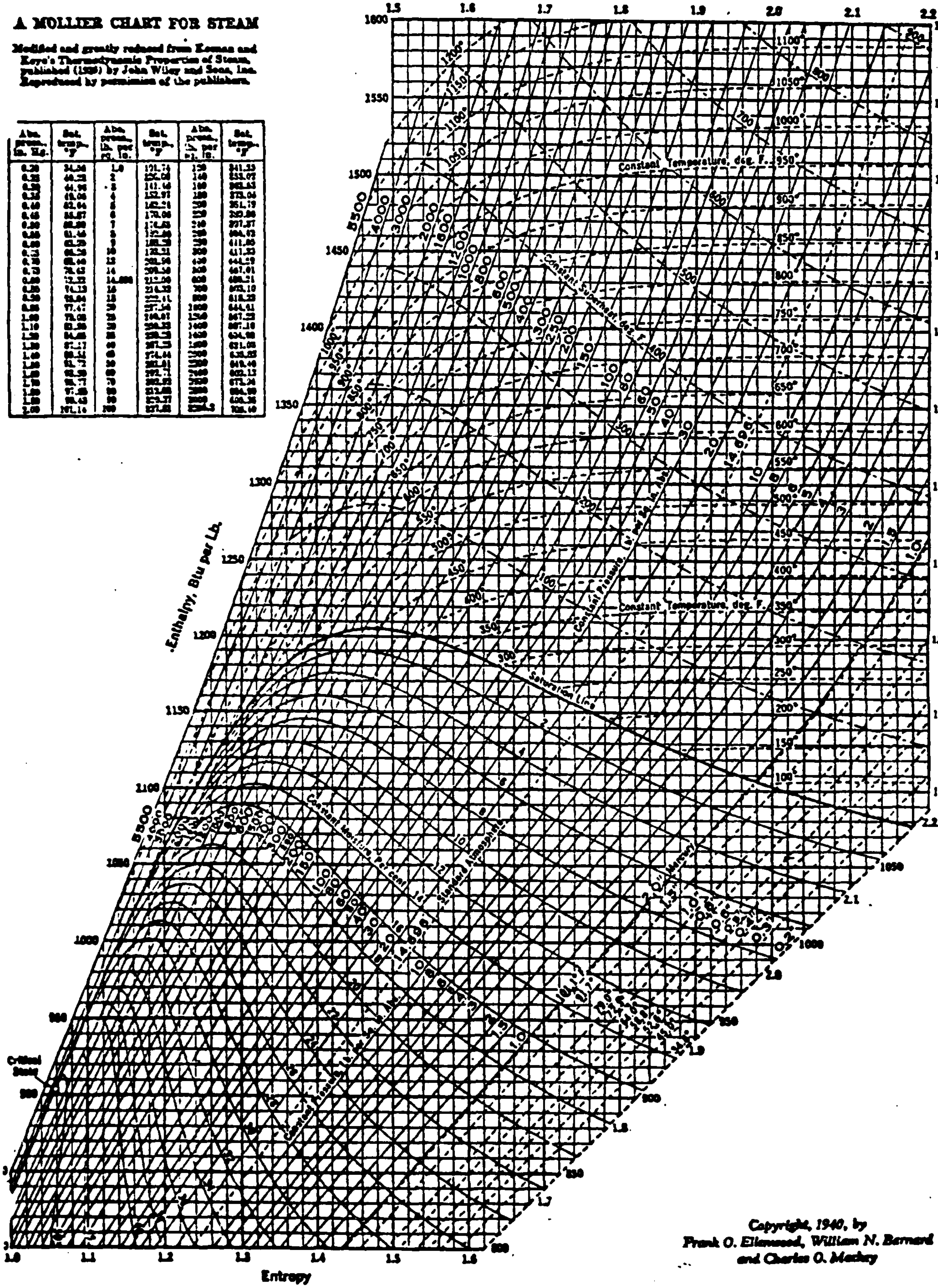
Extraction/Condensing Turbine 700 psig, 750°F Throttle Steam
30 psig Extraction Pressure 1.5 psig Exhaust (Condenser) Pressure



A MOLLIER CHART FOR STEAM

Modified and greatly reduced from Keenan and Keye's Thermodynamic Properties of Steam, published (1936) by John Wiley and Sons, Inc. Reproduced by permission of the publishers.

Abs. press. in. Hg.	Sat. temp. °F	Abs. press. lb. per sq. in.	Sat. temp. °F	Abs. press. lb. per sq. in.	Sat. temp. °F
0.20	34.56	1.0	101.74	120	341.25
0.25	40.22	2	126.08	140	353.02
0.30	44.96	3	141.48	160	363.53
0.35	49.06	4	152.97	180	373.06
0.40	52.64	5	162.21	200	381.79
0.45	55.87	6	170.06	220	389.88
0.50	58.80	7	176.85	240	397.37
0.55	61.46	8	182.86	260	404.42
0.60	63.92	9	188.28	280	411.05
0.65	66.23	10	193.21	300	417.33
0.70	68.36	12	201.96	400	444.59
0.75	70.42	14	209.56	500	467.01
0.80	72.32	14.696	212.00	600	486.21
0.85	74.13	16	216.32	700	503.10
0.90	75.84	18	222.41	800	518.23
0.95	77.47	20	227.96	1000	544.61
1.00	79.03	25	240.07	1200	567.22
1.10	81.96	30	250.33	1400	587.10
1.20	84.66	35	259.28	1600	604.90
1.30	87.17	40	267.25	1800	621.03
1.40	89.51	45	274.44	2000	635.80
1.50	91.72	50	281.01	2200	649.45
1.60	93.80	60	292.71	2400	662.11
1.70	95.77	70	302.92	2600	673.91
1.80	97.65	80	312.03	2800	684.96
1.90	99.43	90	320.27	3000	695.33
2.00	101.14	100	327.81	3206.2	705.40



Enthalpy-entropy diagram for steam.

Performance of Steam Turbines

Efficiency data necessary for calculating the detailed performance of condensing, noncondensing and single-automatic-extraction steam turbines in the ratings most commonly used in industrial plants is given in General Electric Turbine Handbook Section 4721.

Average figures for the efficiency of different turbines and methods of making very rough approximations of turbine performance were given in IPS data book sections .811 and .8111. These methods will be useful in quickly eliminating the least attractive alternates for a particular application.

It is intended that the data included in this section will be useful for quick determination of turbine performance within an accuracy of 5 percent or less. This should be adequate for all normal preliminary application studies.

AUTOMATIC EXTRACTION TURBINES

SINGLE AUTOMATIC EXTRACTION CONDENSING

A convenient calculating procedure and method of preparing a performance chart for a condensing, single-automatic extraction steam-turbine generator set will be outlined below. For the example, assume a unit rated 7500 kw—0.8 PF—9375 kva—3 phase—60 cycles with steam conditions as follows:

Initial Steam....................600 psig—750 F
Extraction Pressure......................50 psig
Exhaust Pressure...........2 inches Hg absolute
Max. Extraction Flow........100,000 lb per hour

All of the calculations needed to prepare the performance chart for this turbine are shown in the calculation procedure below. The various steps are described in more detail in the text which follows the condensed calculation procedure.

Calculation Procedure

For determining performance of single-automatic extraction condensing steam turbines driving 60 cycle generators.

CALCULATIONS

TSR_1 = 7.09 lb per kwhr = Theoretical Steam Rate, from throttle to exhaust (Fig. 3)

TSR_2 = 15.36 lb per kwhr = Theoretical Steam Rate, from throttle to extraction (Fig. 3)

Performance of Steam Turbines

Efficiency = 0.715 (Fig. 4)

A = Full load nonextraction throttle flow

$$= \frac{TSR_1 \times \text{Rated Output}}{\text{Efficiency}}$$

$$= \frac{7.09 \times 7500}{0.715} = 74{,}400 \text{ lb per hr}$$

B = Half load nonextraction throttle flow
= A × half load flow factor (Fig. 5)
= 74,400 × 0.570 = 42,400 lb per hr

$$\frac{TSR_1}{TSR_2} = \frac{7.09}{15.36} \ldots\ldots = 0.461$$

E = Extraction factor . . . . = 0.605 (Fig. 6)

F = Max. required extraction flow = 100,000 lb per hr (assumed for example)

C = Full load throttle flow at max. required extraction flow = A + (E × F) = 74,400 + (0.605 × 100,000) = 134,900 lb per hr

S = Min. flow to exhaust = 4200, or nearest 500 lb = 4000 lb per hr (Fig. 7)

M = Max. permissible throttle flow = 400,000 lb per hr (Fig. 8)

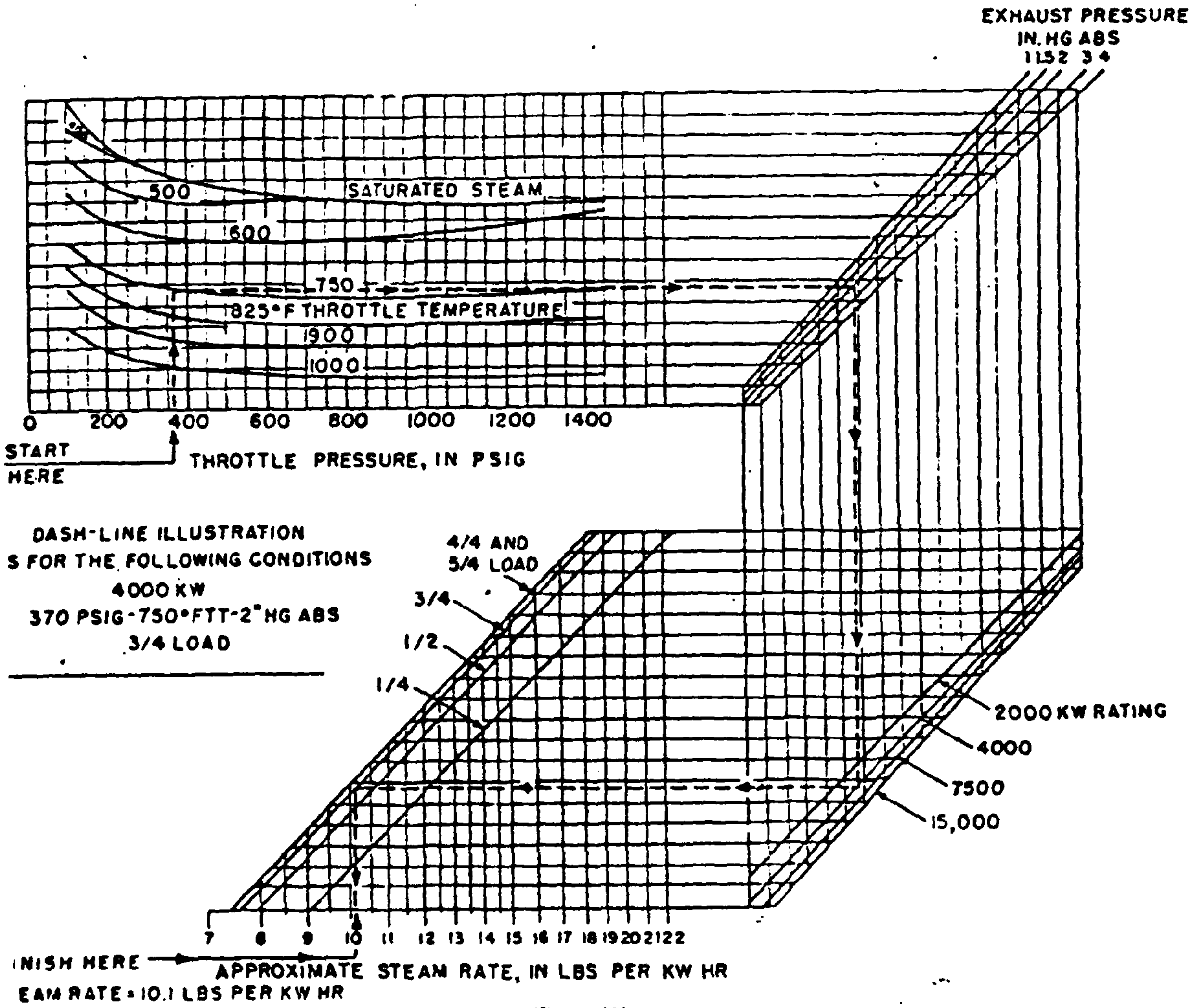
How to Draw Performance Chart

Plot points A, B, and C, and draw the straight lines indicated by Fig. 9 (the example is plotted on Fig. 10). Add the limits:

The minimum flow to exhaust limits is a straight line passing through the point on each line of constant extraction flow where the throttle flow is equal to the extraction flow plus the minimum exhaust flow (S).

The maximum flow to exhaust limit is a straight line passing through the point on each line of constant extraction flow where the throttle flow is equal to the extraction flow plus the full load nonextraction throttle flow (A).

The maximum throttle flow limit may be chosen at any value not in excess of the maximum permissible throttle flow (M), nor in excess of a flow equal to 3 times the full load nonextraction flow (3×A). It is



(Photo 1118549)

Fig. 2. Approximate steam rates of condensing steam turbine-generator units

Performance of Steam Turbines

usually taken as approximately equal to the full load throttle-flow at maximum required extraction (C).

Theoretical Steam Rates

The theoretical steam rates tabulated in Fig. 3 are based on representative initial steam conditions. Inasmuch as each column is headed by both an initial pressure and an initial temperature, this condensed table is not well suited to interpolations.

Where steam conditions are other than those shown in this table, the theoretical steam rates may be derived from a Mollier chart, or read directly from a comprehensive set of Theoretical Steam Rate Tables such as those by Keenan & Keyes, published by the ASME in 1938 and reproduced in General Electric Handbook Section 4707.

Care should be used in determining the theoretical steam rates; they are factors that influence greatly the result.

Efficiency

An approximation of the full-load efficiency with no extraction for single-automatic extraction condensing turbines is given in Fig. 4. The efficiencies

Exhaust Pressure In. Hg Abs	Initial Pressure—Lb per Sq In. Gage																Exhaust Pressure In. Hg Abs
	150	200	250	250	400	400	500	600	600	600	850	850	850	1200	1200	2400	
	Initial Temperature—Degrees Fahrenheit																
	450	500	500	600	600	750	750	600	750	825	825	900	950	900	950	950	
	Initial Superheat																
	84.2	*112.2*	*94*	*194*	*151.9*	*301.9*	*280*	*111.2*	*261.2*	*336.2*	*297.7*	*372.7*	*422.7*	*331.2*	*381.2*	*287*	
0.5	8.39	7.92	7.77	7.32	7.04	6.440	6.333	6.872	6.254	5.986	5.862	5.611	5.454	5.519	5.358	5.286	0.5
1.0	9.09	8.54	8.35	7.85	7.51	6.856	6.727	7.31	6.633	6.340	6.190	5.917	5.747	5.807	5.633	5.535	1.0
1.5	9.59	8.97	8.75	8.22	7.84	7.14	6.995	7.60	6.888	6.578	6.410	6.122	5.944	5.999	5.817	5.700	1.5
2.0	9.98	9.32	9.07	8.52	8.09	7.37	7.20	7.83	7.09	6.766	6.582	6.284	6.097	6.148	5.958	5.828	2.0
2.5	10.32	9.61	9.35	8.76	8.31	7.55	7.38	8.02	7.26	6.923	6.728	6.419	6.223	6.274	6.078	5.933	2.5
3.0	10.62	9.87	9.59	8.98	8.50	7.71	7.53	8.19	7.40	7.05	6.849	6.532	6.332	6.380	6.179	6.023	3.0
3.5	10.89	10.10	9.80	9.18	8.67	7.85	7.67	8.34	7.53	7.17	6.961	6.636	6.431	6.474	6.249	6.102	3.5
4.0	11.14	10.31	10.00	9.36	8.82	7.99	7.79	8.48	7.65	7.28	7.06	6.726	6.520	6.560	6.350	6.175	4.0
4.5	11.37	10.51	10.18	9.52	8.95	8.11	7.91	8.60	7.76	7.39	7.15	6.811	6.600	6.638	6.425	6.240	4.5
5	11.59	10.70	10.35	9.68	9.10	8.23	8.01	8.72	7.86	7.48	7.24	6.981	6.676	6.709	6.493	6.300	5
10	13.37	12.19	11.72	10.91	10.13	9.11	8.83	9.62	8.63	8.20	7.88	7.49	7.24	7.25	7.01	6.750	10
15	14.76	13.34	12.74	11.84	10.88	9.76	9.43	10.28	9.19	8.71	8.34	7.91	7.64	7.63	7.37	7.05	15
20	15.99	14.33	13.63	12.63	11.53	10.30	9.92	10.82	9.64	9.13	8.71	8.25	7.97	7.95	7.67	7.31	20
25	17.13	15.24	14.42	13.35	12.09	10.77	10.35	11.29	10.04	9.49	9.03	8.55	8.25	8.21	7.92	7.52	25
Lb/Sq In. Gage																	Lb/Sq In. Gage
0	18.21	16.07	15.16	14.01	12.59	11.20	10.74	11.71	10.40	9.82	9.31	8.81	8.50	8.44	8.14	7.70	0
5	20.33	17.70	16.56	15.25	13.55	11.99	11.44	12.49	11.05	10.42	9.83	9.28	8.94	8.86	8.53	8.02	5
10	22.44	19.27	17.90	16.44	14.42	12.72	12.10	13.20	11.64	10.96	10.29	9.71	9.34	9.23	8.87	8.30	10
15	24.55	23.81	19.18	17.56	15.24	13.38	12.68	13.85	12.18	11.43	10.71	10.08	9.69	9.56	9.18	8.55	15
20	26.69	22.32	20.45	18.65	16.02	14.02	13.24	14.46	12.68	11.90	11.10	10.43	10.02	9.86	9.46	8.77	20
25	28.94	23.86	21.71	19.74	16.78	14.64	13.78	15.04	13.16	12.33	11.46	10.76	10.33	10.14	9.73	8.98	25
30	31.2	25.42	22.94	20.81	17.52	15.23	14.29	15.60	13.62	12.75	11.80	11.07	10.62	10.40	9.98	9.18	30
35	33.8	27.03	24.20	21.91	18.25	15.82	14.79	16.16	14.07	13.15	12.13	11.37	10.90	10.66	10.22	9.36	35
40	36.4	28.70	25.48	23.03	18.96	16.41	15.29	16.70	14.51	13.54	12.45	11.66	11.17	10.90	10.44	9.54	40
45	39.3	30.5	26.82	24.17	19.69	16.98	15.78	17.23	14.94	13.93	12.77	11.94	11.43	11.14	10.66	9.71	45
50	42.4	32.3	28.20	25.35	20.42	17.57	16.26	17.76	15.36	14.31	13.07	12.21	11.69	11.37	10.88	9.87	50
60	49.4	36.2	31.1	27.76	21.88	18.75	17.20	18.78	16.19	15.05	13.66	12.74	12.19	11.80	11.29	10.17	60
70	57.9	40.5	34.1	30.4	23.35	19.96	18.15	19.80	17.00	15.79	14.22	13.25	12.68	12.22	11.68	10.45	70
80	68.6	45.5	37.5	33.3	24.86	21.21	19.12	20.81	17.81	16.34	14.77	13.76	13.17	12.63	12.05	10.73	80
90		51.3	41.2	36.5	26.44	22.51	20.11	21.84	18.62	17.29	15.32	14.27	13.65	13.02	12.41	10.99	90
100		58.1	45.3	40.0	28.08	23.86	21.12	22.88	19.44	18.05	15.87	14.77	14.13	13.40	12.78	11.24	100
125								25.51	21.56	20.02	17.22	16.03	15.34	14.33	13.65	11.83	125
150				67.9	37.5	31.9	26.75	28.32	23.83	22.12	18.60	17.31	16.37	15.24	14.53	12.39	150
175								31.4	26.27	24.42	20.02	18.64	17.84	16.16	15.41	12.93	175
200					51.1	43.5	33.9	34.7	28.99	26.94	21.32	20.03	19.17	17.09	16.33	13.45	200
250						62.3	43.5	42.4	35.3	32.9	24.77	23.04	22.05	19.03	18.13	14.46	250
300							57.7	32.4	43.6	40.6	28.49	26.52	25.38	21.08	20.10	15.41	300
350								66.1	55.0	51.2	32.8	30.5	29.23	23.32	22.21	16.35	350
400										67.0	38.0	35.4	33.9	25.74	24.57	17.32	400
450											44.4	41.4	39.6	28.42	27.07	18.31	450
500											52.6	49.0	47.0	31.5	29.99	19.31	500
550											63.4	59.0	55.5	35.0	33.3	20.34	550
600													70.1	39.0	37.1	21.42	600
650														43.6	41.6	22.55	650

From "Theoretical Steam Rate Table" by Keenan and Keyes published in 1938 by ASME.

Fig. 3. Condensed table of Theoretical Steam Rates

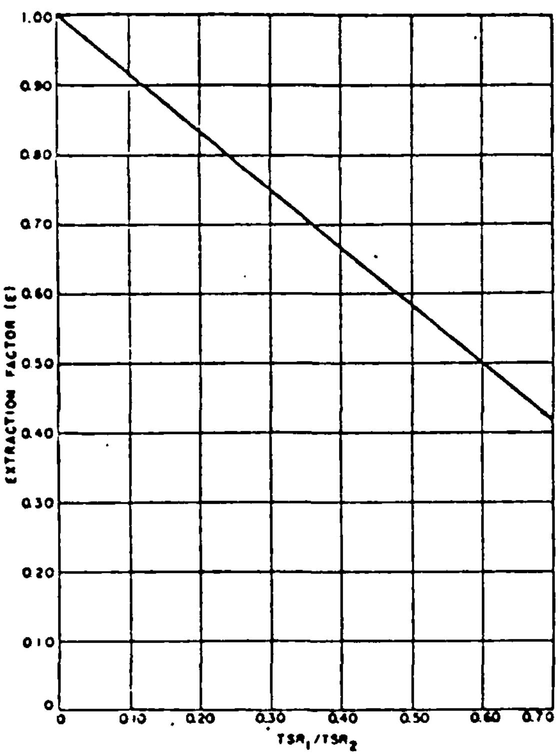
Performance of Steam Turbines

Rating in Kw at 0.8 PF	Main Pressure, in Lb/Sq In. G						
	150	200	250	300	400	600	850
	Efficiency						
2000	.690	.685	.680	.675	.665	.645	—
2500	.700	.695	.690	.685	.675	.660	—
3000	.710	.705	.700	.695	.685	.670	—
3500	.715	.710	.705	.700	.690	.680	—
4000	.720	.715	.710	.705	.700	.685	—
5000	.725	.720	.715	.710	.705	.695	.685
6000	.735	.730	.725	.720	.715	.705	.695
7500	.740	.735	.730	.725	.720	.715	.705

Fig. 4. Full-load non-extraction efficiencies for condensing single-automatic extraction steam turbines

Rating in Kw at 0.8 PF	Factor
2000, 2500, 3000	0.580
3500, 4000, 5000	0.575
6000, 7500	0.570

Fig. 5. Half-load flow factors for condensing single-automatic extraction steam turbines



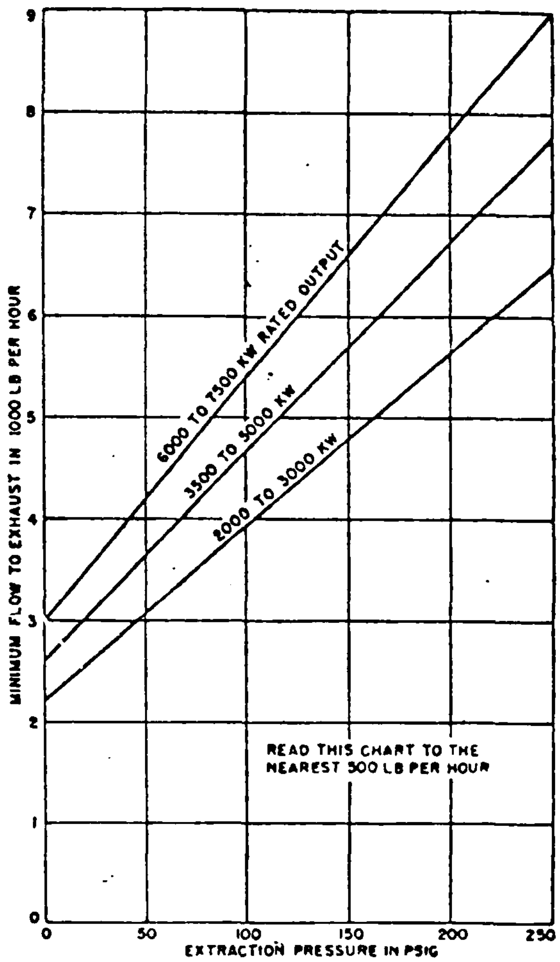
(Photo 1116411)

Fig. 6. Extraction factor versus ratio of Theoretical Steam Rates of condensing single-automatic extraction steam turbines

taken from this table are in the proper magnitude but may be higher or lower than the actual performance guarantees for a specific turbine. If, for example, a turbine were designed to favor performance at high extraction flows, it is probable that the performance guarantees for such a turbine at full load with no extraction would be somewhat poorer than the efficiencies estimated in Fig. 4. In most cases, regardless of design, the error for efficiencies read from this table will be less than 5 percent.

Half-load Flow-factor

The half-load flow-factors (Fig. 5) are approximations that assume that the throttle flow versus output curve at no extraction will be a straight line. The table assumes, too, that all turbines of the same rating, regardless of design, will have the same half-load flow to full-load flow relationship. Obviously this relationship is not a constant one, but the error

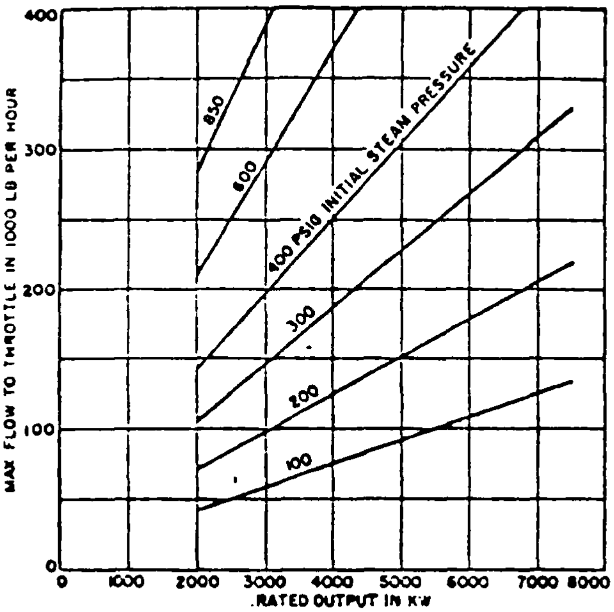


(Photo 1116410)

Fig. 7. Minimum flow to exhaust versus extraction pressure

ELECTRICAL LOAD ON A TYPICAL NON-WORK DAY

Performance of Steam Turbines



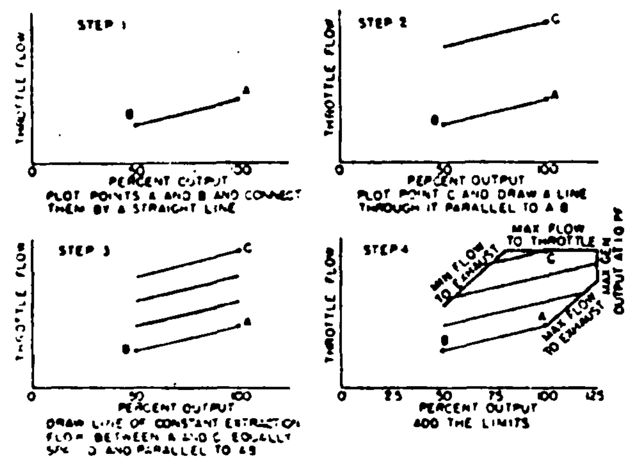
(Photo 1116438)

Fig. 8. Maximum throttle flow versus rated output. Estimates should be limited to those coming within the maximum throttle flows shown on this figure

introduced by this assumption is not appreciable provided the performance chart is not extrapolated below one-half load.

Extraction Factor

The ratio of theoretical steam rates (TSR_1 to TSR_2) is an empirical measure of the extraction factor plotted in Fig. 6. This relationship, and the assumption that all extraction charts are made up of straight lines, parallel to each other and equally spaced, makes possible this estimating method. Such an assumption introduces an error which is more than compensated for by the simplicity it makes possible in the estimating method.



(Photo 1116440)

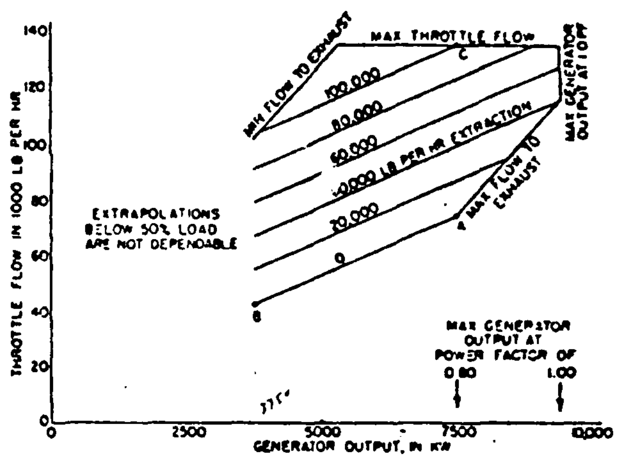
Fig. 9. Step-by-step method of constructing performance chart

The extraction factor is the portion of a pound of steam which must be added to the throttle flow for each pound of steam extracted. Its use is shown in the example.

Max. Required Extraction Flow

The maximum required extraction flow is part of the given conditions for each application of an extraction turbine. No problem is presented by this flow when it is small, but sometimes the desired extraction flow is beyond the turbine's capacity. In such a case the maximum throttle flow limit line (discussed under the heading "Max. throttle flow") will cut off the maximum extraction at the point where full-load is developed with minimum steam flow passing to the exhaust section.

When selecting a flow for the maximum required extraction flow, it will be found desirable to pick a number easily divisible into smaller flows. This is apparent on Fig. 10 where the 100,000 lb per hr flow has been divided into flows of 20, 40, 60, 80, and 100,000 lb per hr for convenience in reading the chart.



(Photo 1116439)

Fig. 10. Performance Chart of the 7500-kw condensing single-automatic extraction steam turbine used in the example. Initial steam condition: 600 PSIG—750 F. Exhaust pressure: 2 inches Hg absolute with automatic extraction at 50 PSIG

Minimum Flow to Exhaust

The chart of minimum flow to exhaust is plotted against extraction pressure with lines for different turbine ratings in Fig. 7. It is not necessary to read this chart more closely than the nearest 500 lb per hr.

The minimum steam flow to exhaust must be adequate to cool the exhaust stages of the turbine.

Fig. 9 gives the steps necessary to prepare the performance chart up to the point where limits are added. The first limit usually added to such a chart is the limit of minimum flow to exhaust, sometimes called the limit of maximum extraction inasmuch as it acts to limit maximum extraction. To add this limit to the chart, two or three points should be plotted

Performance of Steam Turbines

n the lines of constant extraction flow where the hrottle flow is equal to the extraction flow plus the ninimum exhaust flow. Thus, on Fig. 10, with a ninimum exhau flow of 4000 lb per hr, the point n the 100,000 lb per hr limit line will be at 104,000 b per hr throttle flow and, if the 60,000 and 40,000 b per hr extraction lines were extended, they would neet an extension of the minimum flow to exhaust imit line at 64,000 lb per hr and 44,000 lb per hr, espectively.

When placing limits on an extraction chart, it is ıelpful to recall that the flow through the high ressure section is the throttle flow; and that flow o exhaust is equal to the throttle flow minus extraction flow.

Aaximum Flow to Exhaust

The maximum flow to exhaust limit is added to the hart in exactly the same manner as the minimum low to exhaust limit was added. In this estimating nethod the assumption has been made that all turines will be designed with exhaust sections sufficiently large to enable the turbine to carry full rated output with the extraction pressure held constant out no extraction taken from the turbine. This is the usual practice with condensing extraction turbines, although cases are occasionally encountered when it is better to make the exhaust section larger or smaller han the general rule.

In adding the maximum flow to exhaust limit, the ines of constant extraction flow should be extended o the point where they are cut off by this limit or by the limit of generator output. Thus, on Fig. 10, he 20,000 lb per hr extraction flow line is cut by the imit at a throttle flow of 94,400 lb per hr (20,000 lb per hr plus point A), but the 60,000 lb per hr extraction ine is cut off by the limit of generator output, 9375 kw at 1.0 power factor.

Aaximum Generator Output

The usual turbine-generator set has an 0.80 power actor generator, and a turbine capable of carrying ull kva on the generator at 1.0 power factor. This is ndicated as 125 per cent capacity on Fig. 9 and as 9375 kw at 1.0 power factor on Fig. 10.

Aaximum Throttle Flow

The maximum throttle flow from Fig. 8 is not a rue limit in the sense that turbines of the ratings shown could not be built for higher steam flows. Rather it is intended as a warning that such a turbine would be of special design. So also is the limit imposed by a throttle flow equal to three times the full-oad nonextraction flow (i.e., 3 X A). Both of these naximum throttle flow limits are exceeded by many actual extraction turbines, but performance of such nachines is outside the range of this method. When application of turbines outside these limits is inlicated, a manufacturer's turbine specialist or an application engineer familiar with detailed turbine performance should prepare even the most preliminary of estimates.

This estimating method does not include any change in performance for differences in the maximum throttle flow alone. Actually, performance under a given condition will be better if the turbine is designed for a flow no greater than that required to meet the particular condition than if the turbine is designed for a flow much greater than needed. If, for example, the performance of Fig. 10 had been estimated for 150,000 lb per hr extraction flow, the estimated throttle flow at 100,000 lb per hr extraction would remain unchanged, on the basis of this method. In an actual turbine, performance would be better for a turbine designed and operating at 100,000 lb per hr extraction, than for a turbine otherwise the same except designed for 150,000 lb per hr but operating at 100,000 lb per hr extraction. Because of this, the maximum throttle flow should be selected at the lowest value consistent with flexibility to meet present and future needs.

It is true that performance of the condensing extraction type of turbine is easily estimated; it is true that performance of this type of turbine usually pleases both power plant operators and owners. But care should be taken to have each purchase of these turbines approved by an engineer skilled in their application. Only then can assurance be had that these useful machines are making all the gain possible from each particular set of operating conditions.

SINGLE-AUTOMATIC EXTRACTION NONCONDENSING

The Calculation Procedure for determining and plotting the performance of single-automatic extraction noncondensing steam turbines is similar to that for the single-automatic extraction condensing units. The various steps will not be covered in detail as was done in the previous example but a step-by-step calculation procedure for a specific turbine will be worked out below with reference being made to the various curves which give the efficiency and other factors necessary.

For the example, assume a unit rated 7500 kw—0.8 PF—9375 kva—3 phase—60 cycles with steam conditions as follows:

Initial Steam..................600 psig—750 F
Extraction Pressure....................150 psig
Exhaust Pressure.........................40 psig
Max. Extraction Flow..........200,000 lb per hr

Calculation Procedure

For determining performance of single-automatic

Rating in Kw at 0.8 PF	Main Pressure, in Lb/Sq In. G						
	150	200	250	300	400	600	850
	Efficiency						
2000	.700	.690	.685	.675	.660	.630	--
2500	.710	.705	.695	.690	.675	.645	.620
3000	.720	.715	.705	.700	.690	.660	.635
3500	.725	.720	.715	.710	.695	.670	.650
4000	.730	.725	.720	.715	.705	.680	.660
5000	.735	.735	.730	.725	.715	.695	.675
6000	.740	.735	.735	.730	.725	.705	.685
7500	.745	.740	.740	.735	.730	.715	.700

Fig. 11. Full-load non-extraction efficiencies of noncondensing single-automatic extraction steam turbines

Performance of Steam Turbines

noncondensing steam turbine driving 60-cycle generators.

CALCULATIONS

TSR_1 = 14.51 lb per kwhr = Theoretical Steam Rate[3] from throttle to exhaust (Fig. 3)
TSR_2 = 23.83 lb per kwhr = Theoretical Steam Rate, from throttle to extraction (Fig. 3)
Efficiency 0.715 (Fig. 11)

A = Full-load nonextraction throttle flow—

$$= \frac{TSR_1 \times \text{Rated Output}}{\text{Efficiency}}$$

$$= \frac{14.51 \times 7500}{0.715} = 152{,}300 \text{ lb per hr}$$

B = Half-load nonextraction throttle flow—
= A × half-load flow factor (Fig. 12)
= 152,300 × 0.62 = 94,500 lb per hr

$$\frac{TSR_1}{TSR_2} = \frac{14.51}{23.83} \ldots\ldots\ldots\ldots = 0.61$$

E = Extraction factor .... = 0.45 (Fig. 13)
F = Max. required extraction flow.. = 200,000 lb per hr (assumed for example)
C = Full-load throttle flow at max. required extraction flow = A + (E × F) = 152,300 + (0.45 × 200,000) = 242,300 lb per hr
S = Min. flow to exhaust = 6600, or nearest 500 lb = 6500 lb per hr (Fig. 7)
M = Max. permissible throttle flow = 400,000 lb per hr (Fig. 8)

How to Draw Performance Chart

Plot points A, B, and C, and draw straight lines indicated by Fig. 9. Complete the performance chart similar to Fig. 10, as described in the Calculation Procedure for a single-automatic extraction unit.

DOUBLE-AUTOMATIC, EXTRACTION CONDENSING

Calculations required to obtain a complete performance chart for a Double-automatic, Extraction Condensing steam turbine have also been reduced to a method that involves only a few steps of simple arithmetic. Although a completed performance chart may look rather complex at first glance, it is very easy to plot and very easy to use.

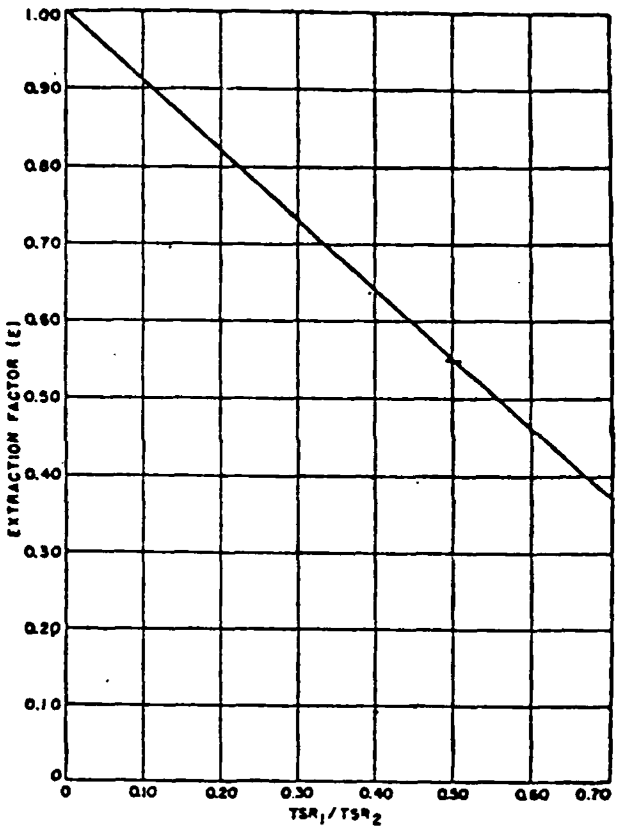
To illustrate how easily a complete performance chart can be prepared, a step-by-step calculation procedure for a specific steam turbine will be worked out below with reference being made to the various curves with the efficiency and other factors necessary.

For the example, assume a unit rated 7500 kw—0.8 PF—9375 kva—3 phase—60 cycles with steam conditions as follows:

	Pressure	Max. Required Flow
Initial Steam	600 psig 750 F	
High Pressure Extraction	150 psig	150,000 lb per hr
Low Pressure Extraction	40 psig	125,000 lb per hr
Exhaust	2 inches Hg absolute	

Rating in Kw at 0.8 PF	Factor
2000, 2500, 3000	0.630
3500, 4000, 5000	0.625
6000, 7500	0.620

Fig. 12. Half-load flow factor for noncondensing single-automatic extraction steam turbines



(Photo 1116412)

Fig. 13. Extraction factor versus ratio of Theoretical Steam Rates for noncondensing single-automatic extraction steam turbines

Calculation Procedure

For determining performance of double-automatic extraction condensing steam turbines driving 60-cycle generators.

CALCULATIONS

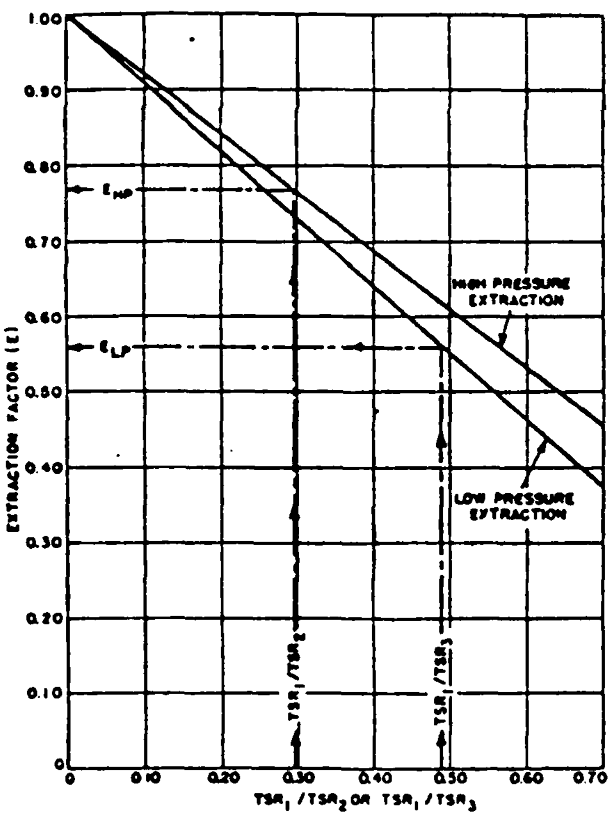
TSR_1 = 7.09 lb per kwhr = Theoretical Steam Rate, from throttle to exhaust (Fig. 3)
TSR_2 = 23.83 lb per hwhr = Theoretical Steam Rate, from throttle to high-pressure extraction (Fig. 3)
TSR_3 = 14.51 lb per kwr = Theoretical Steam Rate, from throttle to low-pressure extraction (Fig. 3)
Efficiency = 0.69 (Fig. 14)

Rating in Kw at 0.8 PF	Main Pressure, in PSI, G						
	150	200	250	300	400	600	850
	Efficiency						
2000	.665	.660	.655	.650	.640	.625	—
2500	.675	.670	.665	.660	.655	.640	—
3000	.685	.680	.675	.670	.665	.650	—
3500	.690	.685	.680	.675	.670	.660	—
4000	.695	.690	.685	.685	.675	.665	—
5000	.705	.700	.695	.690	.685	.675	.665
6000	.710	.705	.700	.700	.690	.680	.675
7500	.715	.710	.710	.705	.700	.690	.685

Fig. 14. Full-load non-extraction efficiencies for condensing double-automatic extraction steam turbines

Rating in Kw at 0.8 PF	Factor
2000, 2500, 3000	0.600
3500, 4000, 5000	0.595
6000, 7500	0.590

Fig. 15. Half-load flow factor for condensing double-automatic extraction steam turbines



(Photo 1116414)

Fig. 16. Extraction factor versus ratio of Theoretical Steam Rates for condensing double-automatic extraction steam turbines

A = Full-load nonextraction throttle flow

$$= \frac{TSR_1 \times \text{Rated Output}}{\text{Efficiency}}$$

$$= \frac{7.09 \times 7500}{0.69} = 77{,}100 \text{ lb per hr}$$

B = Half-load nonextraction throttle flow = A × half-load flow factor (Fig. 15) = 77,100 × 0.59 = 45,500 lb per hr

$$\frac{TSR_1}{TSR_2} = \frac{7.09}{23.83} \ldots\ldots = 0.297$$

E_{HP} = High-pressure extraction factor = 0.77 (Fig. 16)

$$\frac{TSR_1}{TSR_3} = \frac{7.09}{14.51} \ldots\ldots = 0.488$$

E_{LP} = Low-pressure extraction factor = 0.56 (Fig. 16)

F_{HP} = Max. required high-pressure extraction flow = 150,000 lb per hr

F_{LP} = Max. required low-pressure extraction flow = 125,000 lb per hr

C = Full-load throttle flow at max. required low-pressure extraction flow, but zero high-pressure extraction flow
$= A + (E_{LP} \times F_{LP}) = 77{,}100 + (0.56 \times 125{,}000) =$ 147,100 lb per hr

D = Full-load throttle flow at max. required high-pressure extraction flow, but zero low-pressure extraction flow
$= A + (E_{HP} \times F_{HP}) = 77{,}100 + (0.77 \times 150{,}000) =$ 192,600 lb per hr

S_{HP} = Min. flow to intermediate section (Read from Fig. 17 at H.P. extraction pressure) = 6500 lb per hr

S_{LP} = Min. flow to exhaust (Read from Fig. 17 at L.P extraction pressure) = 4000 lb per hr

M = Max permissible throttle flow (Fig. 8) = 400,000 lb per hr

How to Draw Performance Chart

Plot points A, B, C, and D, and draw the straight lines indicated by Fig. 18. (The example is plotted on Fig. 19.)

Prepare a table of limits:

Section of Turbine		Limiting Flow, in Lb per Hr	
		Maximum	Minimum
High Pressure	(Note 1)	= 231,300	0
Intermediate Pressure	C	= 147,100	S_{HP} = 6500
Low pressure	A	= 77,100	S_{LP} = 4000

Note 1. Take the least of the following for max. high-pressure section flow:

M, or 3 × A, or $D + (E_{LP} \times F_{LP})$

M = 400,000 lb per hr

3 × A = 3 × 77,100 = 231,300 lb per hr ← Use

$D + (E_{LP} \times F_{LP}) = 192{,}600 + (0.56 \times 125{,}000) =$ 262,600 lb per hr

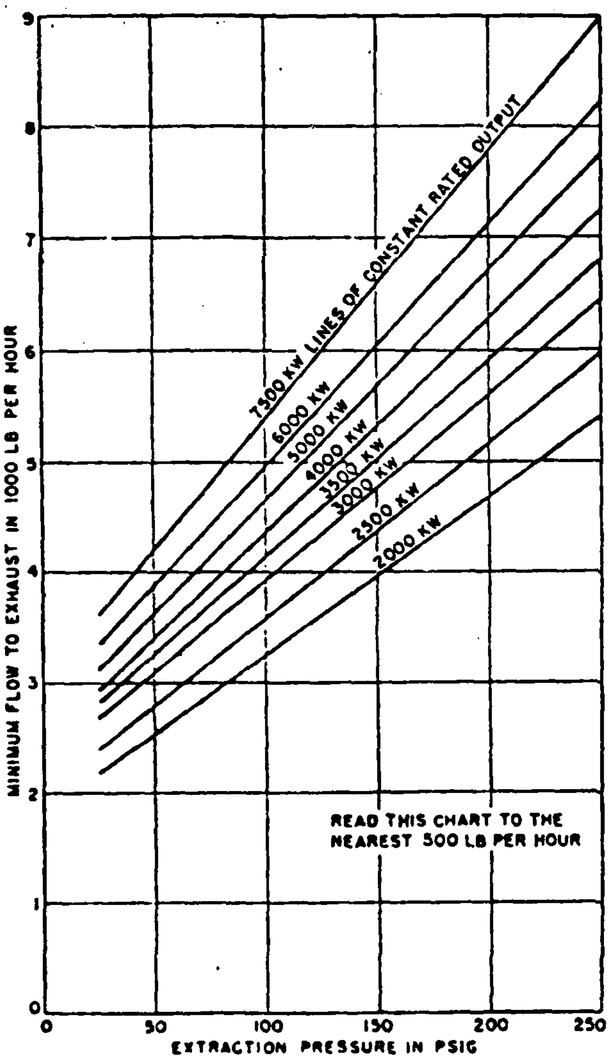
Note that the example problem includes the mini-

mum data needed to prepare a performance chart. These minimum conditions *are: the rated output,* the steam conditions, and the desired maximum extraction flows.

It is usually easier to complete the arithmetic of the calculation procedure before starting to plot the performance chart than to mix the two operations.

This first point, the full-load nonextraction flow, designated as "A," is the basic point used as a pivot for determining the other points. An error made in determining this point will reflect itself throughout all remaining points.

The fact that this basic point A, and the remaining three points, are so easily determined is the greatest disadvantage of this method. Most engineering calculations are of such a complex nature that rule of thumb and other short-cut checks can be made to catch a gross error. Not so in this method. All of the *short-cuts have been taken—any check calculation* would be long and cumbersome—so, even though this method takes less than ten minutes of simple arithmetic, take the time to recheck each figure. The slight additional effort is more than repaid by the confidence that can be put in the result.



(Photo 1116413)

Fig. 17. Minimum flow to section following the high pressure or low pressure automatic extraction opening versus extraction pressure

Plotting the Performance Chart

Fig. 18 shows the steps to take in plotting the data derived in the calculation procedure, and Fig. 19 is the performance chart that resulted from plotting the example problem. Do not be misled by the complex appearance of these charts. They are nothing but straight lines, equally spaced, and parallel to each other. More time may be spent in choosing the scales than in drawing the chart.

Steps 1 and 2 are simple enough, but Step 3 seems unusual. It isn't, however, and no error will be introduced by choosing a slope for the reference line other than 45 degrees. The throttle flow axis can be located at any point, too, but for simplicity it is usually moved enough to the left to prevent overlapping of the high-pressure and low-pressure portions of the performance chart.

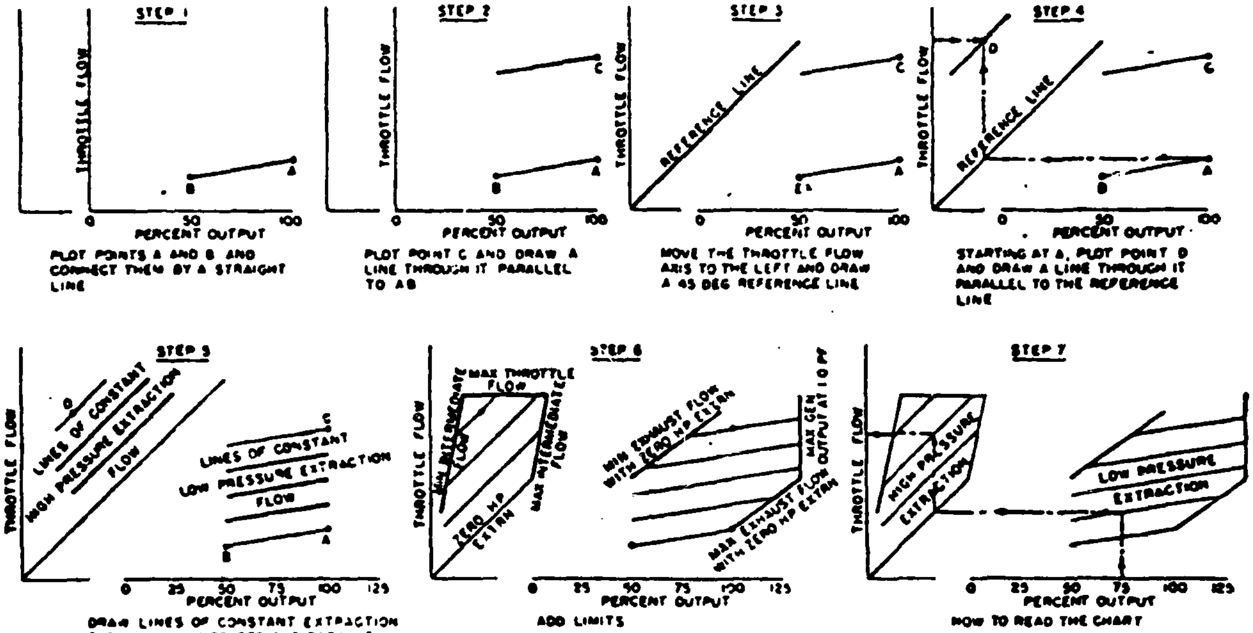
Step 4 consists simply in plotting throttle-flow D at a point directly above the reference line corresponding to full-load with no low-pressure extraction, or, in other words, point A. Then a line is drawn through point *D, parallel to the reference line.*

Except for limits, the chart is completed in Step 5 by drawing lines of constant extraction flow equally spaced and parallel between zero extraction and the maximum. Figure 19, for example, shows low-pressure constant extraction flow lines of 25,000, 50,000, 75,000 and 100,000 lb per hr drawn between 0 and 125,000 lb per hr extraction. And high-pressure constant extraction flow lines of 50,000 and 100,000 lb per hr drawn between 0 and 150,000 lb per hr extraction. These lines are simply for convenience in reading the chart. Their position may be fixed by using dividers, or by a couple of triangles and simple geometry, or by calculation. If calculation is preferred, in should be remembered that each line of constant extraction flow is separated from its neighbor by a distance equal to the extraction flow difference times the extraction factor. Thus, in the case of Fig. 19, each of the lines of high pressure extraction flow are separated by a distance equal to 50,000 x 0.77 or 38,500 lb per hr and the low pressure lines by a distance equal to 25,000 x 0.56 or 14,000 lb per hr.

Adding the Limits to the Chart

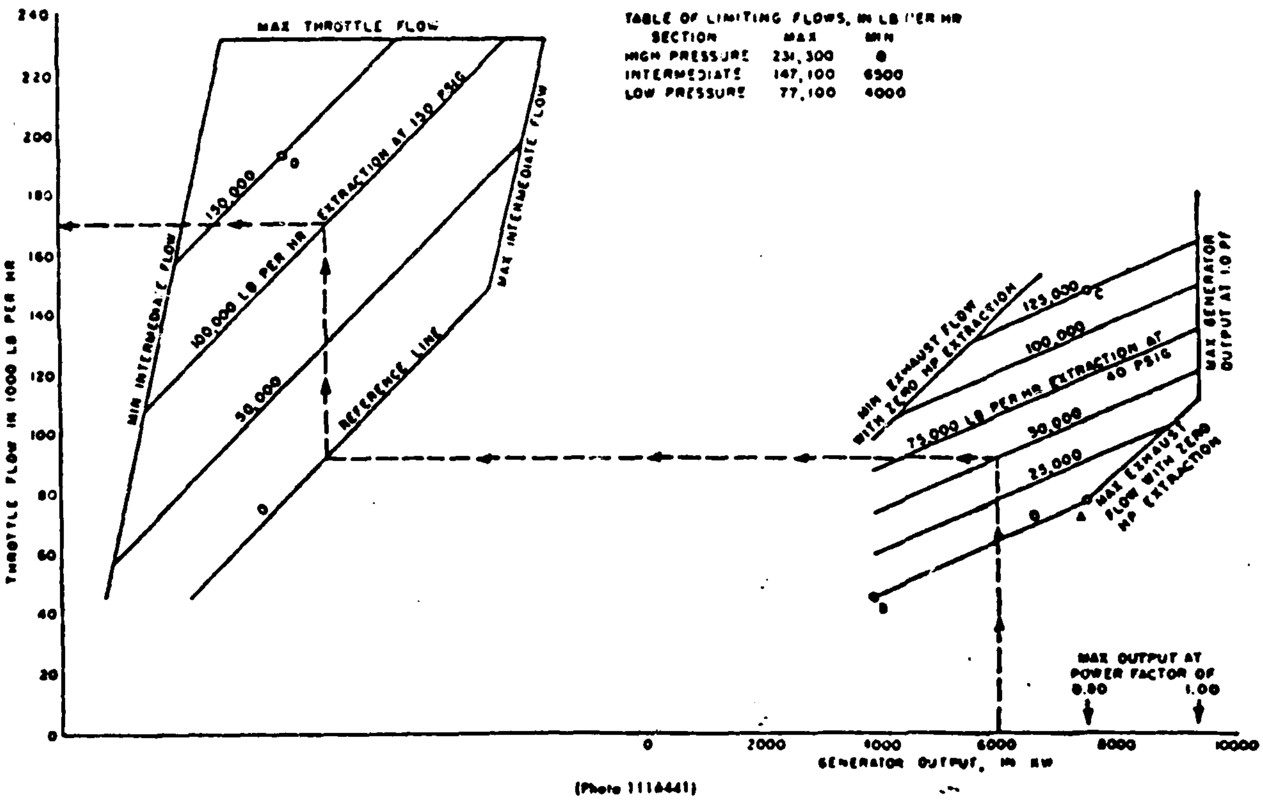
Rather than add all of the limits to the performance chart, it will usually be found time saving to add only a few of the limits and rely on the table of limits for those not shown on the chart. The table of limits derived, as shown in the calculation procedure, is used by reading any desired point from the extraction chart and then checking to see that the flow through the turbine's high-pressure, intermediate, and low-pressure sections are within the limits given in the table. This is done by using the following simple formulae:

Performance of Steam Turbines



(Photo 1116415)

Fig. 18. Step-by-step method of constructing the performance chart



(Photo 1116441)

Fig. 19. Performance chart of the 7500-kw condensing double-automatic extraction steam turbine used in the example. Initial steam conditions: 600 PSIG—750 F. High pressure extraction: 150 PSIG. Low pressure extraction: 40 PSIG. Exhaust pressure: 2 inches Hg absolute

Performance of Steam Turbines

High-pressure section flow = throttle flow

Intermediate section flow = throttle flow minus igh-pressure extraction flow

Low-pressure section flow = throttle flow minus igh-pressure extraction flow minus low-pressure extraction flow

To show, by example, how this works, follow the ashed line on Fig. 19 which shows that:

At an output of 6000 kw with low-pressure extraction of 50,000 lb per hr and high-pressure extraction f 100,000 lb per hr the throttle flow is 170,000 lb er hr

Thus,

High-pressure section flow = 170,000 lb per hr

Intermediate section flow = 170,000 − 100,000 = 70,000 lb per hr

Low-pressure section flow = 170,000 − 100,000 − 50,000 = 20,000 lb per hr

In each case, these flows are between the maximum and minimum section flow limits shown by the table.

The limits given in the table can be plotted on the chart, but the resultant maze of lines may be more confusing than helpful. Usually it suffices to draw on the chart the maximum throttle flow limit, and the maximum generator output limit.

Conclusion

The short-cut methods described in this section give approximations within five per cent in the usual case, but do not show possible gains from any special conditions of operation that exist in most industries.

Manufacturers' turbine specialists or application engineers familiar with turbine applications should be consulted early in studies involving these useful turbines—they are experienced in taking into account the variables that affect the design of each machine.

If the system does not have any back pressure steam turbines, the number entered in column 4 of data card 4 is zero (Ø). Do not prepare data cards 17 and 18. Turn to page 43.

If the system has more than one back pressure steam turbine, the number entered in column 4 of data card 4 is more than one. Prepare one set of data cards (numbers 17 and 18) for each turbine. Place each set of data cards (numbers 17 and 18) after each other in the data deck.

EXAMPLE: Turbine 1 data cards 17 and 18
Turbine 2 data cards 17 and 18
Turbine 3 data cards 17 and 18

Refer to the diagram, steam chart and the General Electric publication for specific information. These are located on pages 40 thru 42.

		VARIABLE NAME AND SYMBOL ON CHARTS
ENTER IN CARD 17:		
Columns: 1 thru 12:	the rated power output at full load; KW.	EED
13 thru 24:	the steam rate or water rate at full load; LB/KWH.	QFD
25 thru 36:	the power output at a partial load KW.	EDP
37 thru 48:	the steam rate or water rate at above partial load, (EDP); LB/KWH.	QFP
49 thru 60:	the efficiency of boiler, decimal form.	T3FRC
61 thru 72:	the percentage of exhaust steam to be exported (decimal form). Accounts for steam used in plant.	T3LIM

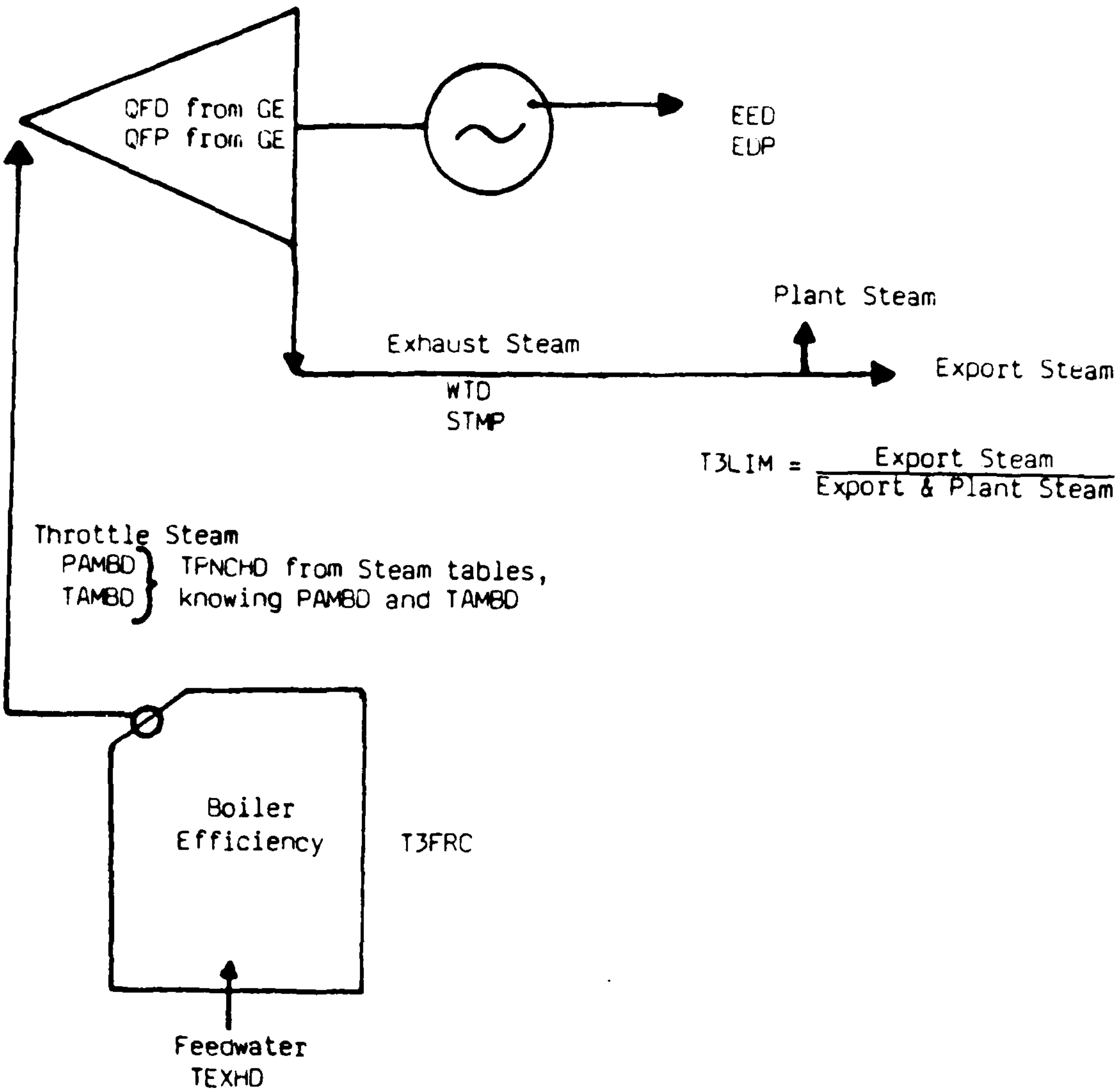
Data card sample on page 90.

ENTER IN CARD 18:

Columns: 1 thru 12:	the enthalpy of the throttle steam; BTU/LB.	TPNCHD
13 thru 24:	the pressure of the throttle steam; PSIG.	PAMBD
25 thru 36:	the temperature of the throttle steam; F.	TAMBD
37 thru 48:	the pressure of the exhaust steam; PSIG.	WTD
49 thru 60:	the temperature of the exhaust steam; F.	STMD
61 thru 72:	the enthalpy of the feed water to the boiler; BTU/LB.	TEXHD

Data card sample on page 90.

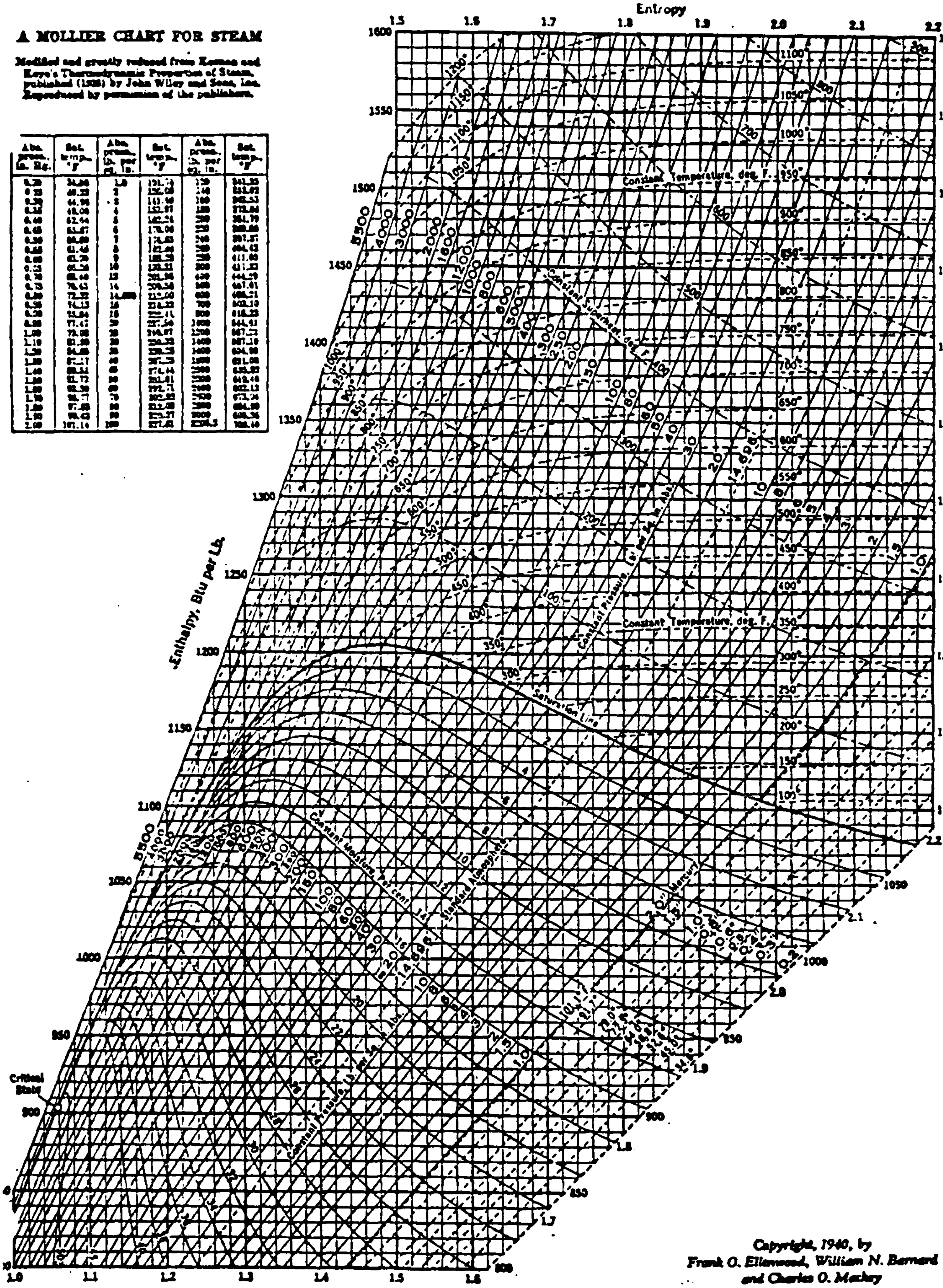
BACK PRESSURE TURBINE



A MOLLIER CHART FOR STEAM

Modified and greatly reduced from Keenan and Keyes's Thermodynamic Properties of Steam, published (1936) by John Wiley and Sons, Inc. Reproduced by permission of the publishers.

Abs. press., in. Hg.	Sat. temp., °F	Abs. press., lb. per sq. in.	Sat. temp., °F	Abs. press., lb. per sq. in.	Sat. temp., °F
0.20	34.86	1.0	101.74	120	341.25
0.25	40.32	2	126.08	140	353.02
0.30	44.96	3	141.48	160	363.53
0.35	48.06	4	152.97	180	373.06
0.40	52.34	5	162.24	200	381.79
0.45	55.57	6	170.06	220	389.86
0.50	58.80	7	176.85	240	397.37
0.55	61.46	8	182.86	260	404.42
0.60	63.79	9	188.28	280	411.05
0.65	65.94	10	193.21	300	417.33
0.70	68.66	12	201.96	400	444.59
0.75	70.63	14	209.56	500	467.01
0.80	72.32	14.696	212.00	600	486.21
0.85	74.13	16	216.32	700	503.10
0.90	75.84	18	222.41	800	518.23
0.95	77.42	20	227.96	1000	544.61
1.00	79.03	25	240.07	1200	567.22
1.10	81.88	30	250.33	1400	587.10
1.20	84.58	35	259.28	1600	604.90
1.30	87.17	40	267.25	1800	621.02
1.40	89.51	45	274.44	2000	635.80
1.50	91.72	50	281.01	2200	649.45
1.60	93.80	60	292.71	2400	662.11
1.70	95.77	70	302.92	2600	673.91
1.80	97.65	80	312.03	2800	684.96
1.90	99.43	90	320.27	3000	695.33
2.00	101.14	100	327.81	3206.2	705.40



Enthalpy-entropy diagram for steam.

Performance of Steam Turbines

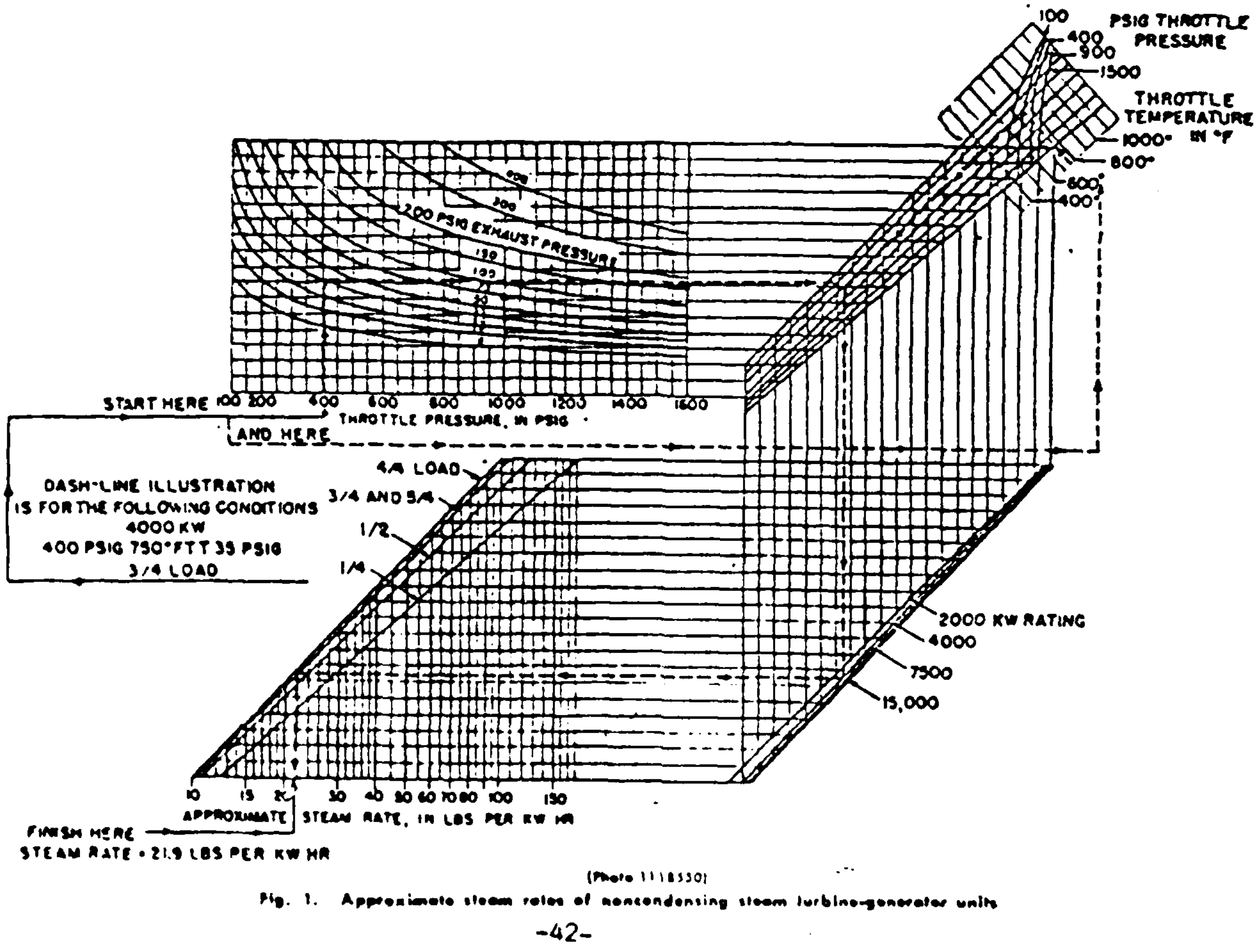
Efficiency data necessary for calculating the detailed performance of condensing, noncondensing and single-automatic-extraction steam turbines in the ratings most commonly used in industrial plants is given in General Electric Turbine Handbook Section 4721.

Average figures for the efficiency of different turbines and methods of making very rough approximations of turbine performance were given in IPS data book sections .811 and .8111. These methods will be useful in quickly eliminating the least attractive alternates for a particular application.

It is intended that the data included in this section will be useful for quick determination of turbine performance within an accuracy of 5 percent or less. This should be adequate for all normal preliminary application studies.

NONEXTRACTION TURBINES

The data plotted on Fig. 1 shows the steam consumed by noncondensing steam turbines rated 2000 kw through 15,000 kw at various load conditions.



(Photo 1118330)

Fig. 1. Approximate steam rates of noncondensing steam turbine-generator units

ELECTRICAL LOAD ON A TYPICAL WORK DAY

Prepare one set of data cards 19, 20, and 21 for each month.

Place each set of data cards (numbers 19, 20, and 21) after each other in the data deck.

EXAMPLE: January - data cards 19, 20, and 21
February - data cards 19, 20, and 21
March - data cards 19, 20, and 21

Contin . preparing the data cards until you have 12 sets (January thru December)

Enter the value of the electrical load (KW) of each hour on a typical work day.

ENTER IN CARD 19:

Columns:	1 thru 10:	0100
	11 thru 20:	0200
	21 thru 30:	0300
	31 thru 40:	0400
	41 thru 50:	0500
	51 thru 60:	0600
	61 thru 70:	0700
	71 thru 80:	0800

ENTER IN CARD 20:

Columns:	1 thru 10:	0900
	11 thru 20:	1000
	21 thru 30:	1100
	31 thru 40:	1200
	41 thru 50:	1300
	51 thru 60:	1400
	61 thru 70:	1500
	71 thru 80:	1600

ENTER IN CARD 21:

Columns:	1 thru 10:	1700
	11 thru 20:	1800
	21 thru 30:	1900
	31 thru 40:	2000
	41 thru 50:	2100
	51 thru 60:	2200
	61 thru 70:	2300
	71 thru 80:	2400

Variable name: ELLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 1; (Work day)

Data card samples on pages 91 and 92.

ELECTRICAL LOAD ON A TYPICAL NON-WORK DAY

Prepare one set of data cards 22, 23, and 24 for each month.

Place each set of data cards (numbers 22, 23, and 24) after each other in the data deck.

EXAMPLE:	January	- data cards 22, 23, and 24
	February	- data cards 22, 23, and 24
	March	- data cards 22, 23, and 24

Continue preparing the data cards until you have 12 sets (January thru December).

Enter the value of the electrical load (KW) of each hour on a typical non-work day.

ENTER IN CARD 22:

Columns:	1 thru 10:	0100
	11 thru 20:	0200
	21 thru 30:	0300
	31 thru 40:	0400
	41 thru 50:	0500
	51 thru 60:	0600
	61 thru 70:	0700
	71 thru 80:	0800

ENTER IN CARD 23:

Columns:	1 thru 10:	0900
	11 thru 20:	1000
	21 thru 30:	1100
	31 thru 40:	1200
	41 thru 50:	1300
	51 thru 60:	1400
	61 thru 70:	1500
	71 thru 80:	1600

ENTER IN CARD 24:

Columns:	1 thru 10:	1700
	11 thru 20:	1800
	21 thru 30:	1900
	31 thru 40:	2000
	41 thru 50:	2100
	51 thru 60:	2200
	61 thru 70:	2300
	71 thru 80:	2400

Variable name: ELLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 2; (Non-work day)

Data card samples on pages 93 and 94.

STEAM LOAD ON A TYPICAL WORK DAY

Prepare one set of data cards 25, 26, and 27 for each month.

Place each set of data cards (numbers 25, 26, and 27) after each other in the data deck.

EXAMPLE: January - data cards 25, 26, and 27
February - data cards 25, 26, and 27
March - data cards 25, 26, and 27

Continue preparing the data cards until you have 12 sets (January thru December).

Enter the value of the steam load (LB/HR) of each hour on a typical work day.

ENTER IN CARD 25:

Columns:	1 thru 10:	0100
	11 thru 20:	0200
	21 thru 30:	0300
	31 thru 40:	0400
	41 thru 50:	0500
	51 thru 60:	0600
	61 thru 70:	0700
	71 thru 80:	0800

ENTER IN CARD 26:

Columns:	1 thru 10:	0900
	11 thru 20:	1000
	21 thru 30:	1100
	31 thru 40:	1200
	41 thru 50:	1300
	51 thru 60:	1400
	61 thru 70:	1500
	71 thru 80:	1600

ENTER IN CARD 27:

Columns:	1 thru 10:	1700
	11 thru 20:	1800
	21 thru 30:	1900
	31 thru 40:	2000
	41 thru 50:	2100
	51 thru 60:	2200
	61 thru 70:	2300
	71 thru 80:	2400

Variable Name: STMLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 1; (Work day)

Data card samples on pages 95 and 96.

STEAM LOAD ON A TYPICAL NON-WORK DAY

Prepare one set of data cards 28, 29, and 30 for each month.

Place each set of data cards (numbers 28, 29, and 30) after each other in the data deck.

EXAMPLE: January - data cards 28, 29, and 30
February - data cards 28, 29, and 30
March - data cards 28, 29, and 30

Continue preparing the data cards until you have 12 sets (January thru December).

Enter the value of the steam load (LB/HR) of each hour on a typical non-work day.

ENTER IN CARD 28:

Columns: 1 thru 10:	0100
11 thru 20:	0200
21 thru 30:	0300
31 thru 40:	0400
41 thru 50:	0500
51 thru 60:	0600
61 thru 70:	0700
71 thru 80:	0800

ENTER IN CARD 29:

Columns: 1 thru 10:	0900
11 thru 20:	1000
21 thru 30:	1100
31 thru 40:	1200
41 thru 50:	1300
51 thru 60:	1400
61 thru 70:	1500
71 thru 80:	1600

ENTER IN CARD 30:

Columns: 1 thru 10:	1700
11 thru 20:	1800
21 thru 30:	1900
31 thru 40:	2000
4[illegible] 50:	2100
51 [illegible]	2200
61 thru [illegible]	2300
71 thru 80:	2400

Variable Name: STMLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 1; (Non-work day)

Data card samples on pages 97 and 98.

The rate structures of the utility companies vary as to geographic location. Demand pricing is generally used by the eastern states. Time of day pricing is generally used by the western states. Contact the utility company to determine the rate structure applicable to this study.

Refer to pages 48 thru 52 for typical examples of rate structures for the West and East coast.

ENTER IN CARD 31:		VARIABLE NAME
Columns: 1 thru 5:	the month during which the summer rate begins (numeric form; ex: May = 5).	SUMON1
6 thru 10:	the month during which the winter rate begins (numeric form; ex: November = 11).	SUMON2

This data is used in conjunction with the time of day rate scheduling. They are "dummy" variables in the version of CELCAP with the demand rate schedule.

Data card sample on page 99.

If the rate structure to be used is demand pricing:

Enter in data cards 32, 33, 34, and 35, columns 1 thru 24, 1.

Data card samples on pages 100 and 101.

TURN TO PAGE 57.

This is simply a "dummy" variable for the version of CELCAP with the demand pricing rate schedule.

If the rate structure to be used is time of day pricing: TURN TO PAGE 53.

Newport Electric Corporation
Newport, Rhode Island

R.I.P.U.A. No. 302-E
Superseding R.I.P.U.A. No. 302-D

WHOLESALE POWER SERVICE

AVAILABILITY:

Service is available hereunder for any power purchases, but not for resale, to any customer who will enter into a contract, satisfactory to Company, to purchase all of its requirements of electric energy for power purposes from the Company for a period of not less than five (5) years provided Company has adequate generating and/or transmission facilities available to serve such customers over and above the requirements of existing customers. Service shall be supplied through a single point of delivery and one metered supply unless for the sole convenience of Company more than one delivery point or one metered supply will be provided. Electric energy for the lighting purposes of customer may also be purchased hereunder provided customer supplies and maintains the necessary transformers thereafter.

CHARACTER OF SERVICE:

Service supplied hereunder shall be three phase, 60 cycle electric energy at a nominal voltage of 23,000 volts, or higher.

RATE:

Demand Charge:

First 5,000 kw of billing demand or less per month	- $16,650
All additional kw of billing demand	- 2.30 per kw

Energy Charges:

First 340 hours use of billing demand per month	- 3.07¢ per kwh
All additional kwh used per month	- 2.79¢ per kwh

DETERMINATION OF BILLING DEMAND:

The billing demand in kilowatts for each month shall be the greater of (a) the maximum demand adjusted for power factor each month, (b) 75% of the maximum billing demand established by customer during any of the immediately preceding eleven months, (c) 50% of the maximum billing demand established by customer during the life of the contract, or (d) 5,000 kilowatts.

POWER FACTOR ADJUSTMENT:

For billing demand purposes, when the power factor of customer as measured hereunder is above 80% lagging and below 90% lagging no adjustment of the maximum demand as measured in kilowatts for each billing month shall be made. When the power factor of customer as measured hereunder shall in any month fall below 80% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. When the power factor of customer as measured hereunder shall be any month rise above 90% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. For the purposes of the faster adjustment, the power factor shall in no event by considered as grater than unity.

MINIMUM CHARGE:

The monthly minimum charge for service hereunder shall be the demand charge plus the energy charge for 170 hours use of the billing demand of such month, subject to Fuel, Primary Metering and Transformer Ownership adjustments.

FUEL ADJUSTMENT CLAUSE:

All energy delivered hereunder, including the amount in the minimum charge, shall be subjected to the provisions of the Company's Standard Fuel Adjustment Clause.

PRIMARY METERING:

If the electric energy delivered to customer is measured at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder, there will be credited against the amount determined under the preceding provisions two and one-half percent (2-1/2%) of the demand charge and energy charge for such month.

TRANFORMER OWNERSHIP:

If customer utilizes electric energy at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder or if customer provides all transformers which may be required to reduce the line voltage to the level at which the electric energy is to be used by customer, there will be credited against the amount determined under the preceding provisions twelve cents ($0.12) for each kilowatt of billing demand for such month.

TERMS AND CONDITIONS:

(1) Service hereunder shall be subject to the Company's Terms and Conditions in effect from time to time and not inconsistent with any specific provisions of this rate schedule.

(2) The term "year" shall mean each twelve-month period beginning after the date of the first delivery of electric energy to customer under this rate schedule.

(3) The term "demand" shall mean customer's maximum average rate of taking electric energy hereunder during any fifteen-minute period during the billing month as measured by a standard kilowatt demand meter.

(4) The customer's power factor shall be determined from the registrations of suitable instruments, permanently installed, or by periodic tests at the option of the Company.

PAYMENT OF BILLS:

Bills are rendered net and payment is due within ten days from date bill is rendered.

Approval Issued: November 1, 1977 Effective: November 1, 1977

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5137-E

Cancelling Revised Cal P.U.C. Sheet No. 5020-E

Schedule No. TOU-8

GENERAL SERVICE — LARGE

APPLICABILITY

Applicable to three-phase general service, including lighting and power, supplied directly from lines of transmission voltage, or where for the Company's operating convenience service is supplied from lines of distribution voltage.

This schedule is applicable for all customers of record on August 23, 1977, served on Schedule No. A-8 and thereafter is applicable to all customers whose monthly maximum demand exceeds 5,000 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 4,500 kW for 12 consecutive months may elect to take service on any other applicable schedule.

TERRITORY

Within the entire territory served, excluding Santa Catalina Island.

RATES

	Per Meter Per Month
Customer Charge:	$1,075.00
Demand Charge (to be added to Customer Charge):	
All kW of on-peak billing demand, per kW	$ 5.05
Plus all kW of mid-peak billing demand, per kW	0.65
Plus all kW of off-peak billing demand, per kW	No Charge
Energy Charge (to be added to Demand Charge):	
All on-peak kWh, per kWh	0.530¢
Plus all mid-peak kWh, per kWh	0.380¢
Plus all off-peak kWh, per kWh	0.230¢

Minimum Charge:

The monthly minimum charge shall be the sum of the monthly Customer and Demand Charges. The monthly Demand Charge shall be not less than the charge for 25% of the maximum on-peak demand established during the preceding 11 months.

Daily time periods will be based on Pacific Standard Time and are defined as follows:

On-peak: 12:00 noon to 6:00 p.m. summer weekdays except holidays
5:00 p.m. to 10:00 p.m. winter weekdays except holidays

Mid-peak: 8:00 a.m. to 12:00 noon and 6:00 p.m. to 10:00 p.m. summer weekdays except holidays
8:00 a.m. to 5:00 p.m. winter weekdays except holidays

Off-peak: All other hours.

Off-peak holidays are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas.

For initial implementation of this schedule by the Company, winter shall consist of the billing periods for the six regularly scheduled monthly billings beginning with the first regularly scheduled billing ending after November 14, 1977. Thereafter, regularly scheduled monthly billings shall include six summer billing periods followed by six winter billing periods. In no event will winter include scheduled billing periods ending after May 31 of any year.

(Continued)

(To be inserted by utility)	Issued by	(To be inserted by Cal. P.U.C.)
Advice Letter No. 478-E	Edward A. Myers, Jr. (Name)	Date Filed December 27, 1978
Decision No. 89711, 89783		Effective January 1, 1979
	Vice President (Title)	Resolution No.

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5148-E

Cancelling Revised Cal. P.U.C. Sheet No. 5050-E

Schedule No. TOU-8

GENERAL SERVICE — LARGE

(Continued)

SPECIAL CONDITIONS

1. **Voltage:** Service will be supplied at one standard voltage.

2. **Maximum Demand:** Maximum demands shall be established for the daily on-peak, mid-peak, and off-peak periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments to be supplied by the Company, during any 15-minute metered interval, but not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule No. 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

3. **Billing Demand:** Separate billing demands for the on-peak, mid-peak, and off-peak daily time periods shall be established for each monthly billing period. The billing demand for each daily time period shall be the maximum demand for that daily time period occurring during the respective monthly billing period.

4. **Voltage Discount:** The charges before adjustments will be reduced by 1% for service delivered and metered at a nominal voltage of 33,000 volts and by 2% for service delivered and metered at a nominal voltage of 66,000 volts or over.

5. **Power Factor Adjustment:** The charges will be adjusted each month for reactive demand. The charges will be increased by 20 cents per kilovar of maximum reactive demand imposed on the Company in excess of 20% of the maximum number of kilowatts.

The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering to be supplied by the Company during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

6. **Temporary Discontinuance of Service:** Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

7. **Contracts:** An initial three-year facilities contract may be required where applicant requires new or added serving capacity exceeding 2,000 kVA.

8. **Energy Cost Adjustment:** The rates above are subject to adjustment as provided for in Part G of the Preliminary Statement. The applicable energy cost adjustment billing factors and fuel collection balance adjustment billing factor set forth therein will be applied to all kWh billed under this schedule.

9. **Tax Change Adjustment:** The rates above are subject to adjustment as provided for in Part I of the Preliminary Statement. The applicable tax change adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

10. **Conservation Load Management Adjustment:** The rates above are subject to adjustment as provided for in Part J of the Preliminary Statement. The applicable conservation load management adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

(To be inserted by utility)	Issued by	(To be inserted by Cal. P.U.C.)
Advice Letter No. 478-E	Edward A. Myers, Jr. (Name)	Date Filed December 27, 1978
Decision No. 89711, 89783		Effective January 1, 1979
	Vice President (Title)	Resolution No.

TIME OF DAY PRICING

The following data cards (numbers 32, 33, 34, and 35) are used to designate when the charges for purchased electrical energy are being made at the peak rate, the mid-peak rate, or at the off-peak rate.

Choose Ø: if the demand is in an off-peak period.
Choose 1: if the demand is in a mid-peak period.
Choose 2: if the demand is at the peak period.

TYPICAL WORK DAY DURING THE SUMMER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 32:

Column:	
1:	0100
2:	0200
3:	0300
4:	0400
5:	0500
6:	0600
7:	0700
8:	0800
9:	0900
10:	1000
11:	1100
12:	1200
13:	1300
14:	1400
15:	1500
16:	1600
17:	1700
18:	1800
19:	1900
20:	2000
21:	2100
22:	2200
23:	2300
24:	2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KYRHLF = 1; (Summer months)
Nowork = 1; (Work day)

Data card sample on page 102.

TYPICAL WORK DAY DURING THE WINTER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 33:

Column:

1:	0100
2:	0200
3:	0300
4:	0400
5:	0500
6:	0600
7:	0700
8:	0800
9:	0900
10:	1000
11:	1100
12:	1200
13:	1300
14:	1400
15:	1500
16:	1600
17:	1700
18:	1800
19:	1900
20:	2000
21:	2100
22:	2200
23:	2300
24:	2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KYRHLF = 2; (Winter months)
Nowork = 1; (Work day)

Data card sample on page 102.

TYPICAL NON-WORK DAY DURING THE SUMMER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 34:

Column:	1:	0100
	2:	0200
	3:	0300
	4:	0400
	5:	0500
	6:	0600
	7:	0700
	8:	0800
	9:	0900
	10:	1000
	11:	1100
	12:	1200
	13:	1300
	14:	1400
	15:	1500
	16:	1600
	17:	1700
	18:	1800
	19:	1900
	20:	2000
	21:	2100
	22:	2200
	23:	2300
	24:	2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KYRHLF = 1; (Summer months)
Nowork = 2; (Non-work day)

Data card sample on page 103.

TYPICAL NON-WORK DAY DURING THE WINTER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 35:

Column:
1: 0100
2: 0200
3: 0300
4: 0400
5: 0500
6: 0600
7: 0700
8: 0800
9: 0900
10: 1000
11: 1100
12: 1200
13: 1300
14: 1400
15: 1500
16: 1600
17: 1700
18: 1800
19: 1900
20: 2000
21: 2100
22: 2200
23: 2300
24: 2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KYRHLF = 2; (Winter months)
Nowork = 2; (Non-work day)

Data card sample on page 103.

ENTER IN CARD 36:

The number of days per month.

Columns:	1 thru 6:	January
	7 thru 12:	February
	13 thru 18:	March
	19 thru 24:	April
	25 thru 30:	May
	31 thru 36:	June
	37 thru 42:	July
	43 thru 48:	August
	49 thru 54:	September
	55 thru 60:	October
	61 thru 66:	November
	67 thru 72:	December

Variable name: PERMO (month)
Month = 1, 12; (January thru December)

Data card sample on page 104.

THE CURRENT PRICES OF FUEL, ELECTRICITY, OPERATING, AND MAINTENANCE COSTS

ENTER IN CARD 37:

			VARIABLE NAME
Columns:	1 thru 10:	the fuel cost for the gas turbine; $/MBTU*. This will normally be a premium fuel; either #2 fuel oil or natural gas.	GTFLC
	11 thru 20:	the fuel cost for the diesel engine, $/MBTU. This will normally be a premium fuel, either #2 fuel oil or natural gas.	DSLFLC
	21 thru 30:	the fuel cost for the steam turbine, $/MBTU.	STTFLC
	31 thru 40:	the fuel cost for the auxiliary fired boiler, $/MBTU.	BLRFLC

* NOTE: MBTU = million BTU.

Data card sample on page 105.

For specific information relating to the operating and maintenance costs, refer to the table and figures on pages 59 thru 65.

ENTER IN CARD 38:

	Columns	Description	VARIABLE NAME
Columns:	1 thru 10:	the O&M cost for the gas turbine as a peaking unit; $/MWH*.	GTPKOM
	11 thru 20:	the O&M cost for the gas turbine as a cogenerating unit; $/MWH.	GTCGOM
	21 thru 30:	the O&M cost for the diesel engine as a peaking unit; $/MWH.	DSPKOM
	31 thru 40:	the O&M cost for the diesel engine as a cogenerating unit; $/MWH.	DSCGOM
	41 thru 50:	the O&M cost for the steam turbine as a peaking unit; $/MWH.	STPKOM
	51 thru 60:	the O&M cost for the steam turbine as a cogenerating unit; $/MWH.	STCGOM
	61 thru 70:	the O&M cost for the auxiliary fired boiler; $/KLB* steam.	BLROM
	71 thru 80:	the O&M cost for the waste heat recovery boiler; $/KLB steam.	WASTOM

* NOTE: MWH = Megawatt hours.
KLB = Kilo pounds (1000 pounds).

Data card sample on page 106.

ENTER IN CARD 39:

	Columns	Description	VARIABLE NAME
Columns:	1 thru 10:	the fixed O&M cost per month for the gas turbine; $/month.	GTOM
	11 thru 20:	the fixed O&M cost per month for the diesel engine; $/month.	DSOM
	21 thru 30:	the fixed O&M cost per month for the steam turbine; $/month.	STOM
	31 thru 40:	the fixed O&M cost per month for the auxiliary fired boiler; $/month.	BLFOM
	41 thru 50:	the O&M cost per KLB* of steam generated by the high pressure boiler; $/KLB.	THRSTM

* NOTE: KLB = Kilo pounds (1000 pounds).

Data card sample on page 106.

Table 1. Estimating Procedures for Operating and Maintenance Costs for Cogeneration Systems

Potential Contributor to O&M Costs	Estimating Procedure or Figure
A. Steam Turbine Cogeneration Plants, Coal-Fired	
Central Receiving and Handling Facility	Figure 11[a]
Hauling, Receiving Facility - Generating Plant (if not co-located)	Figure 12[a]
Steam Generating Facility	Figure 13[a]
Air Pollution Control System	Figure 14[a]
Electrical Generating Facility	(2.5% x capital)/yr[b], where Figure 7 shows capital investment
Hauling of Waste to Temporary Storage (if required)	Figure 15[a] plus Figure 12
Waste Disposal (annual cost, knowing average tons per hour throughout year)	10 miles from base[a]: $\$135,000\ (TPH/2.8)^{0.6}$ if $TPH > 2.8$; \$135,000 if $TPH \leq 2.8$ 50 miles from base[a]: $\$140,000\ (TPH/2.2)^{0.75}$ if $TPH > 2.2$; \$140,000 if $TPH \leq 2.2$
B. Steam Turbine Cogeneration Plants, Oil- or Natural Gas-Fired	
Steam Generating Facility	$\$1.10/10^3$ lb of steam[c] (for natural gas or distillate oil) $\$1.50/10^3$ lb of steam[c] (for residual oil)
Electrical Generating Facility	(2.5% x capital)/yr[b], where Figure 7 shows capital investment
Air Pollution Control System (only if designed to use high sulfur fuel)	Figure 14[a]
C. Combustion Turbine/Generator Sets With Exhaust Heat Boilers	
Turbine/Generator Set	4.0 mils/kW-hr[d] for units operating on "continuous" duty, and for units ≤ 2 MWe on peaking duty 7.0 mils/kW-hr[e] for units > 2 MWe on peaking duty
Exhaust Heat Boiler	$\$1.00/10^3$ lb of steam[f]

continued

Table 1. Continued

Potential Contributor to O&M Costs	Estimating Procedure or Figure
D. Diesel/Generator Sets With Exhaust Heat Boiler	
Diesel/Generator Set	13 mils/kW-hr[g]
Exhaust Heat Boiler	$1.00/$10^3$ lb of steam[f]

NOTE: For conventional steam generating facilities, use the appropriate parts of lists A and B above.

[a]Reference 2.

[b]Reference 1.

[c]Based on data from Long Beach Naval Shipyard and Sewell's Point Naval Complex compiled by CEL.

[d]Based on correspondence with Garrett Airesearch and Pacific Gas and Electric personnel. Includes costs for major overhauls.

[e]Based on data from San Diego Gas and Electric.

[f]CEL estimate.

[g]Based on Reference 3.

The fuel cost contribution to generated power is

$$FPC = (HR_{EFF})(CF)(1/10^3)$$

where FPC = fuel contribution to power costs, mils/kW-hr

CF = cost of fuel, \$/million Btu

For power from the cogeneration system to be economically attractive to the Navy, the fuel cost contribution must be sufficiently less than the cost of purchased power to allow for capital recovery and O&M. For the power to be economically attractive to a utility company, the fuel cost contribution must compare favorably with costs they experience or anticipate in their system.

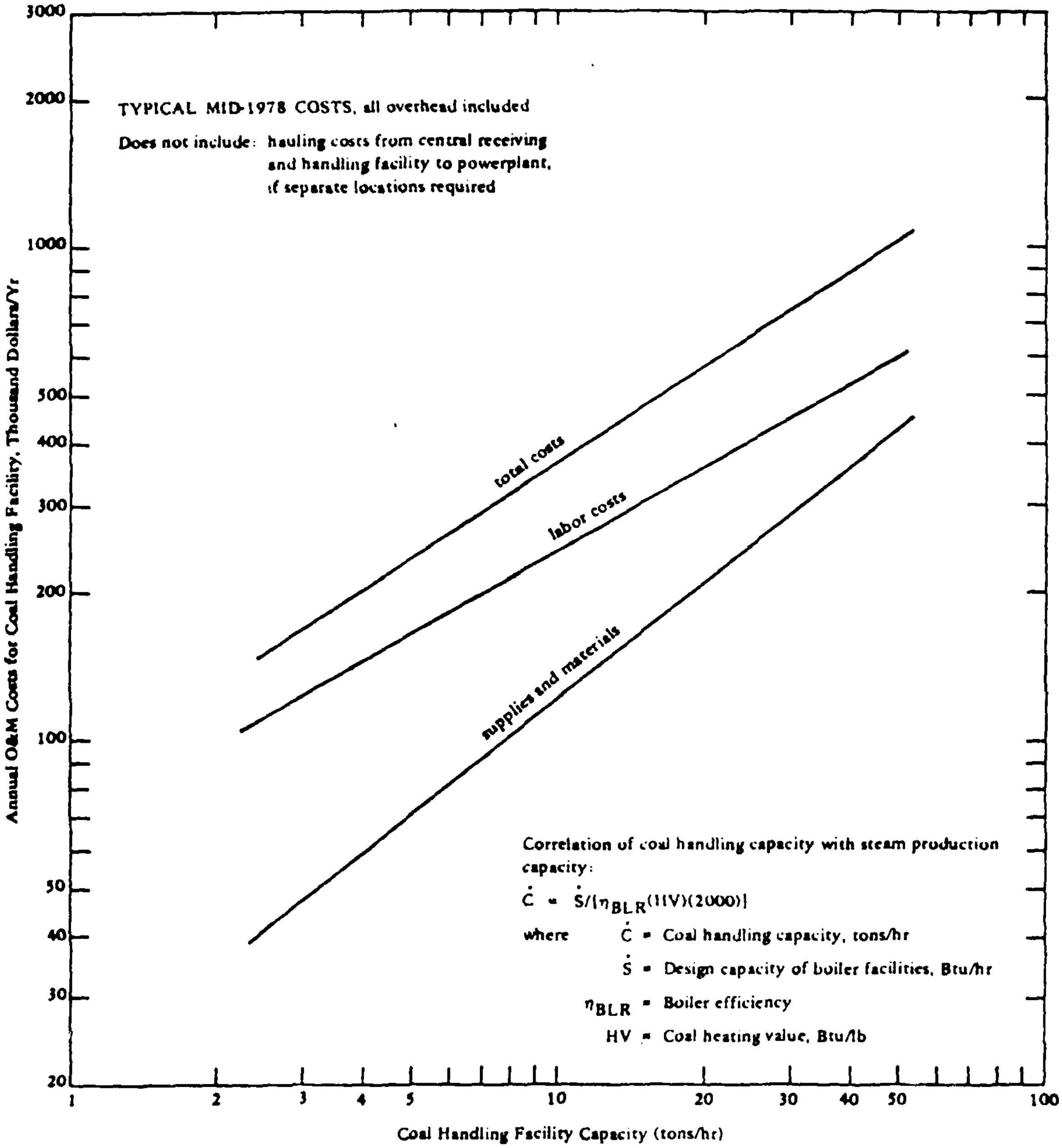


Figure 11. Operating and maintenance costs for central receiving and coal-handling facilities with stockpile.

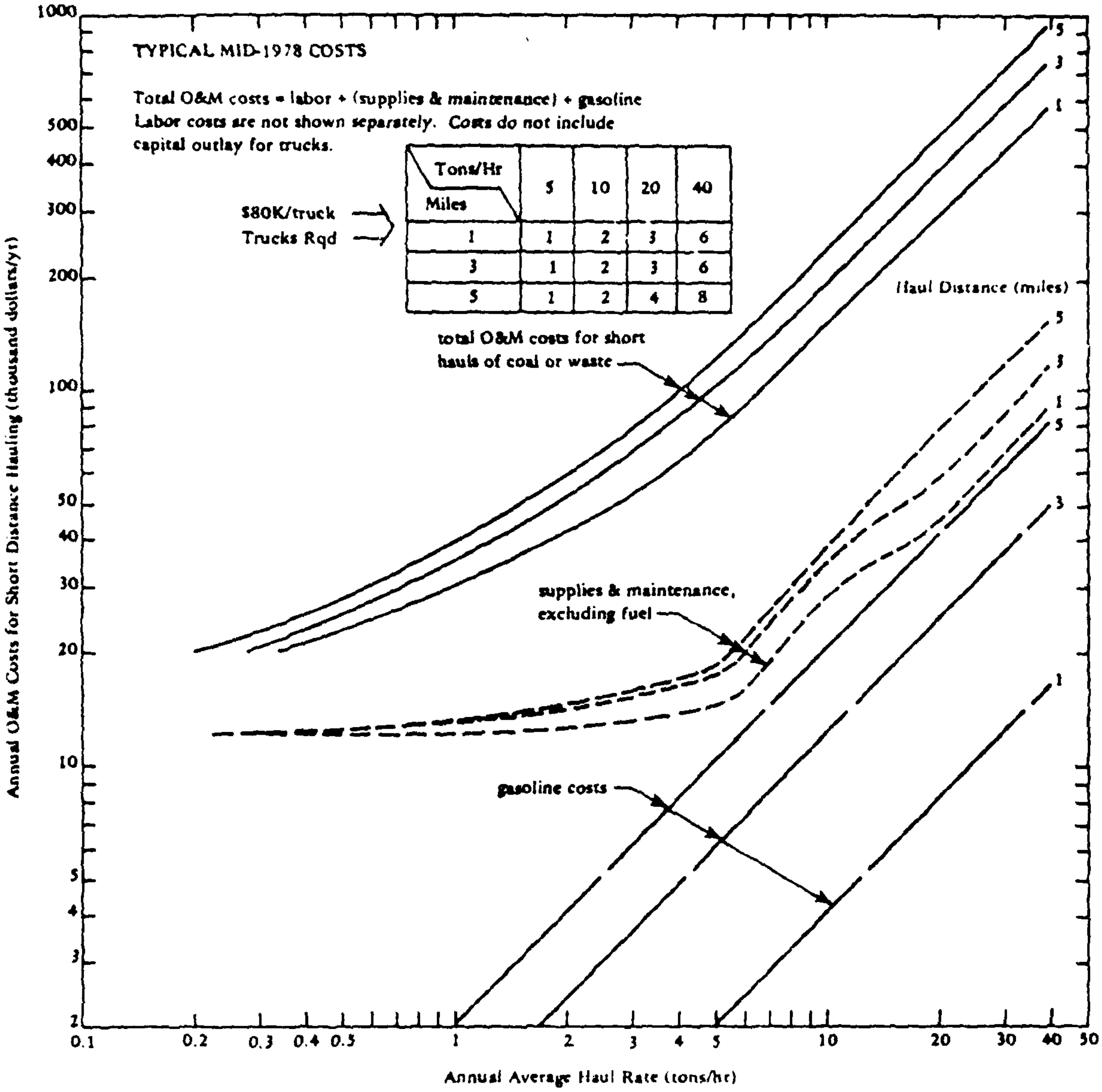


Figure 12. Operating and maintenance costs for short distance hauling of coal or solid waste.

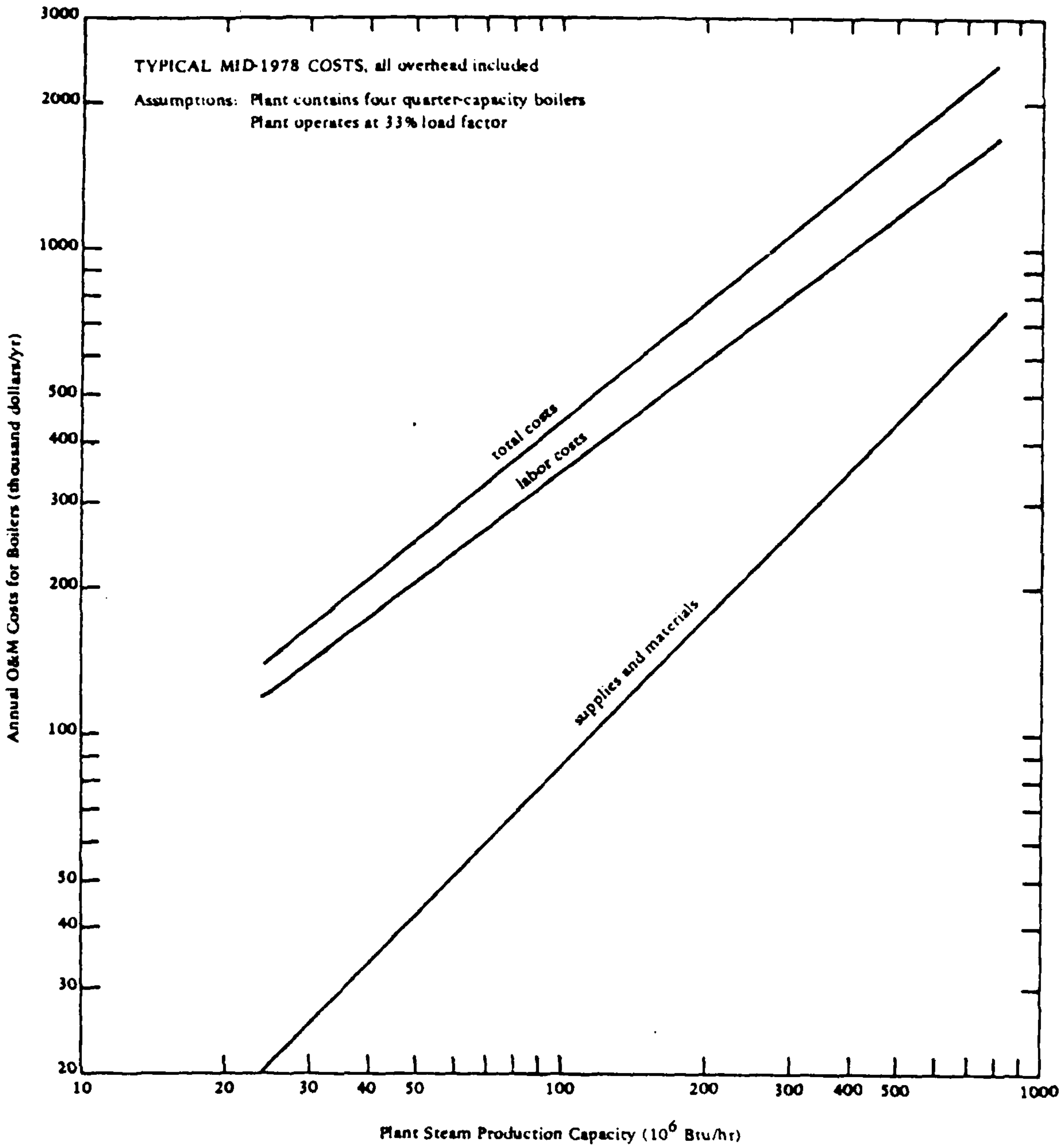


Figure 13. Operating and maintenance costs for coal-fired steam boilers.

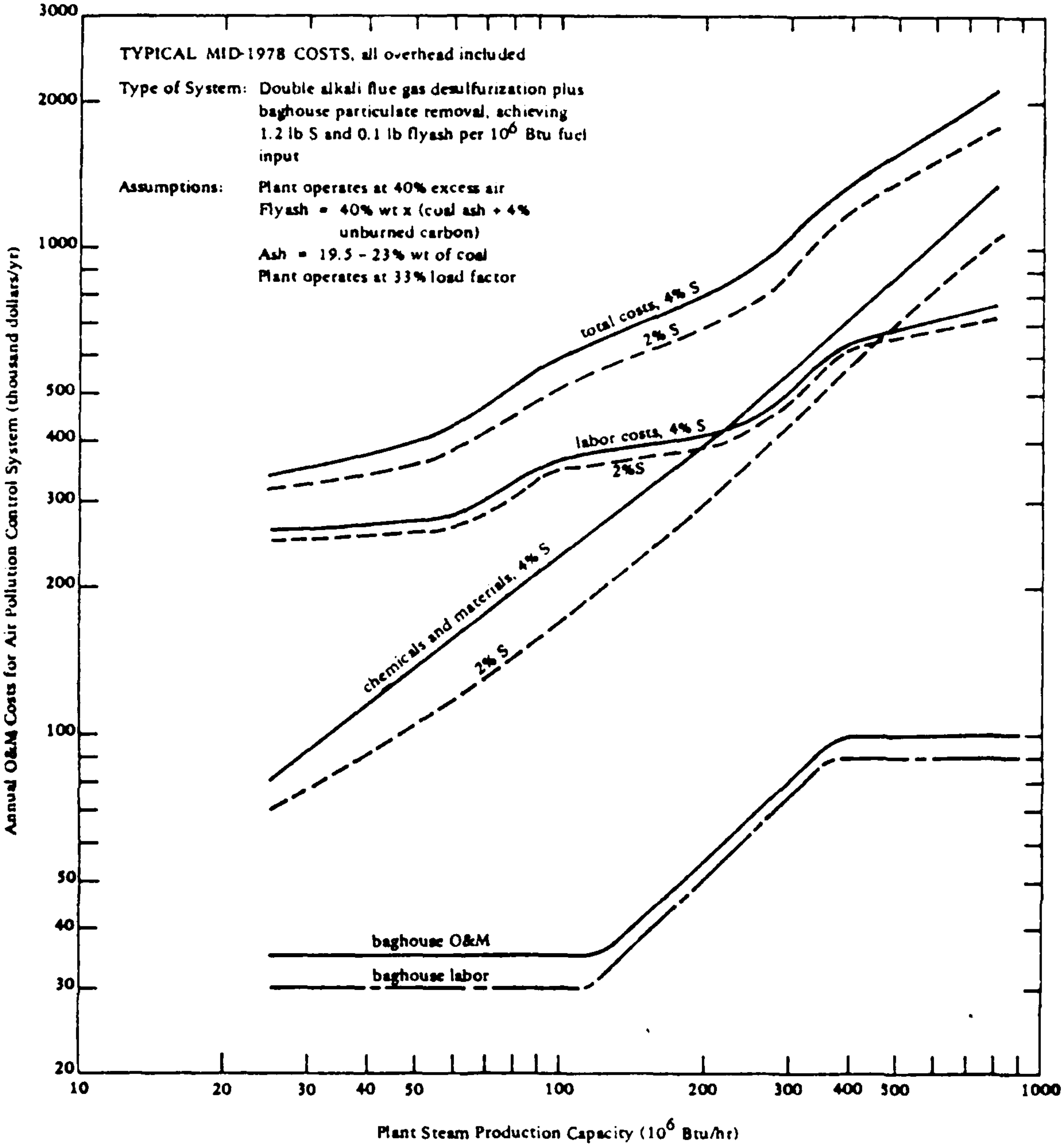


Figure 14. Operating and maintenance costs for air pollution control of coal-fired generating plants.

REFERENCES

1. Department of Energy, Office of Industrial Programs. Report No. HCP/M 8688-01: Guidelines for developing state cogeneration policies; April 1979. Resource Planning Associates, Apr 1979. (Contract No. EC-77-01-8688).

2. Civil Engineering Laboratory. Contract Report CR 79.012: Coal-fired boilers at Navy bases, Navy energy guidance study phases II and III. Bechtel National, Inc., May 1979. (Contract No. N68305-77-C-0003).

3. Bulletin 3382270 and other information from the Cummins Cogeneration Company, Suite 1134 Empire State Bldg, New York, N.Y.

The rate structures of the utility companies vary as to geological location.

Demand pricing is generally used by the eastern states and time of day pricing is generally used by the western states. Contact the utility company to determine the rate structure applicable to this study.

This version of the CELCAP program is set up for the demand pricing rate structure. The instructions that follow for data cards 40 and 41 are for the demand pricing rate structure only. If the area of study utilizes the time of day rate structure, the program will have to be modified. A version of the time of day rate structure program is available at the Civil Engineering Laboratory (refer to page i). The instructions for data cards 40 and 41 for the time of day rate structure are on page 70.

Refer to pages 67 thru 69 for a typical example of the demand rate schedule from Newport Electric Corporation, Newport, RI.

ENTER IN CARD 40:

Columns			VARIABLE NAME
Columns:	1 thru 10:	the customer charge per meter/per month, $.	CHMTR
	11 thru 20:	the demand charge for the first 5000 KW* of the billing demand or less per month; $.	DCHPK
	21 thru 30:	the demand charge for all of the additional KW of the billing demand, $/KW.	DCHOFF
	31 thru 40:	the energy charge for the first 340 hours of use of the billing demand per month; cents/KWH*.	ECHPK
	41 thru 50:	the energy charge for all of the additional KWH of use per month; cents/KWH*.	ECHOFF
	51 thru 60:	the fuel adjustment charge; $/KWH.	FLADJ

* NOTE: KW = Kilowatt.
KWH = Kilowatt hours.

Data card sample on page 107

ENTER IN CARD 41:

Columns			VARIABLE NAME
Columns:	1 thru 10:	the billing demand KW, it is 75% of the maximum billing demand established by the customer during any of the immediately preceding eleven months.	DMDPK

If the demand pricing rate structure is being used: TURN TO PAGE 73.

Data card sample on page 107.

WHOLESALE POWER SERVICE

AVAILABILITY:

Service is available hereunder for any power purchases, but not for resale, to any customer who will enter into a contract, satisfactory to Company, to purchase all of its requirements of electric energy for power purposes from the Company for a period of not less than five (5) years provided Company has adequate generating and/or transmission facilities available to serve such customers over and above the requirements of existing customers. Service shall be supplied through a single point of delivery and one metered supply unless for the sole convenience of Company more than one delivery point or one metered supply will be provided. Electric energy for the lighting purposes of customer may also be purchased hereunder provided customer supplies and maintains the necessary transformers thereafter.

CHARACTER OF SERVICE:

Service supplied hereunder shall be three phase, 60 cycle electric energy at a nominal voltage of 23,000 volts, or higher.

RATE:

Demand Charge:

First 5,000 kw of billing demand or less per month	- $16,650
All additional kw of billing demand	- 2.30 per kw

Energy Charges:

First 340 hours use of billing demand per month	- 3.07¢ per kwh
All additional kwh used per month	- 2.79¢ per kwh

DETERMINATION OF BILLING DEMAND:

The billing demand in kilowatts for each month shall be the greater of (a) the maximum demand adjusted for power factor each month, (b) 75% of the maximum billing demand established by customer during any of the immediately preceding eleven months, (c) 50% of the maximum billing demand established by customer during the life of the contract, or (d) 5,000 kilowatts.

POWER FACTOR ADJUSTMENT:

For billing demand purposes, when the power factor of customer as measured hereunder is above 80% lagging and below 90% lagging no adjustment of the maximum demand as measured in kilowatts for each billing month shall be made. When the power factor of customer as measured hereunder shall in any month fall below 80% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. When the power factor of customer as measured hereunder shall be any month rise above 90% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. For the purposes of the faster adjustment, the power factor shall in no event by considered as grater than unity.

MINIMUM CHARGE:

The monthly minimum charge for service hereunder shall be the demand charge plus the energy charge for 170 hours use of the billing demand of such month, subject to Fuel, Primary Metering and Transformer Ownership adjustments.

FUEL ADJUSTMENT CLAUSE:

All energy delivered hereunder, including the amount in the minimum charge, shall be subjected to the provisions of the Company's Standard Fuel Adjustment Clause.

PRIMARY METERING:

If the electric energy delivered to customer is measured at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder, there will be credited against the amount determined under the preceding provisions two and one-half percent (2-1/2%) of the demand charge and energy charge for such month.

TRANFORMER OWNERSHIP:

If customer utilizes electric energy at the li oltage, not less than 23,000 volts, at which it is transmitted to the o elivery hereunder or if customer provides all transformers which may be required to reduce the line voltage to the level at which the electric energy is to be used by customer, there will be credited against the amount determined under the preceding provisions twelve cents ($0.12) for each kilowatt of billing demand for such month.

TERMS AND CONDITIONS:

(1) Service hereunder shall be subject to the Company's Terms and Conditions in effect from time to time and not inconsistent with any specific provisions of this rate schedule.

(2) The term "year" shall mean each twelve-month period beginning after the date of the first delivery of electric energy to customer under this rate schedule.

(3) The term "demand" shall mean customer's maximum average rate of taking electric energy hereunder during any fifteen-minute period during the billing month as measured by a standard kilowatt demand meter.

(4) The customer's power factor shall be determined from the registrations of suitable instruments, permanently installed, or by periodic tests at the option of the Company.

PAYMENT OF BILLS:

Bills are rendered net and payment is due within ten days from date bill is rendered.

Approval Issued: November 1, 1977

Effective: November 1, 1977

TIME OF DAY RATE STRUCTURE

Refer to pages 71 and 72 for a typical example of the time of day rate schedule from the Southern California Edison Company, Rosemead, CA.

ENTER IN CARD 40:

			VARIABLE NAME
Columns:	1 thru 10:	the customer charge per meter/per month, $.	CHMTR
	11 thru 20:	the demand charge of the on-peak KW; $/KW.	DCHPK
	21 thru 30:	the demand charge of the mid-peak KW; $/KW.	DCHMID
	31 thru 40:	the demand charge of the off-peak KW; $/KW.	DCHOFF
	41 thru 50:	the energy charge of the on-peak KWH; $/KWH.	ECHPK
	51 thru 60:	the energy charge of the mid-peak KWH; $/KWH.	ECHMID
	61 thru 70:	the energy charge of the off-peak KWH; $/KWH.	ECHOFF
	71 thru 80:	the fuel adjustment charge; $/KWH.	FLADJ

Data card sample on page 108.

ENTER IN CARD 41:

			VARIABLE NAME
Columns:	1 thru 10:	the on-peak demand; KW.*	DMDPK
	11 thru 20:	the mid-peak demand; KW.**	DMDMID
	21 thru 30:	the off-peak demand; KW.***	DMDOFF

Assumptions for on-peak, mid-peak, and off-peak demand levels:

1. Five engines with the combined capacity of 515 + 500 + 7,500 + 5,000 = 18,565 KW. Firm capacity (calculated assuming the two largest engines are down) = 515 + 500 + 5,000 = 6,015 KW.

*2. On-peak demand = 20,000 KW - 6,015 KW = 13,985 KW. (Based on load peak = 20,000 KW during on-peak hours.)

**3. Mid-peak demand = 17,000 KW - 6,015 KW = 10,985 KW. (Based on load peak = 17,000 KW during mid-peak hours.)

***4. Off-peak demand = 15,000 KW - 6,015 KW = 8,985 KW. (Based on load peak = 15,000 KW during off peak hours.)

Data card sample on page 108.

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5147-E

Cancelling Revised Cal. P.U.C. Sheet No. 5020-E

Schedule No. TOU-8

GENERAL SERVICE — LARGE

APPLICABILITY

Applicable to three-phase general service, including lighting and power, supplied directly from lines of transmission voltage, or where for the Company's operating convenience service is supplied from lines of distribution voltage.

This schedule is applicable for all customers of record on August 23, 1977, served on Schedule No. A-8 and thereafter is applicable to all customers whose monthly maximum demand exceeds 5,000 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 4,500 kW for 12 consecutive months may elect to take service on any other applicable schedule.

TERRITORY

Within the entire territory served, excluding Santa Catalina Island.

RATES

	Per Meter Per Month
Customer Charge:	$1,075.00
Demand Charge (to be added to Customer Charge):	
All kW of on-peak billing demand, per kW	$ 5.05
Plus all kW of mid-peak billing demand, per kW	0.65
Plus all kW of off-peak billing demand, per kW	No Charge
Energy Charge (to be added to Demand Charge):	
All on-peak kWh, per kWh	0.530¢
Plus all mid-peak kWh, per kWh	0.380¢
Plus all off-peak kWh, per kWh	0.230¢

Minimum Charge:

The monthly minimum charge shall be the sum of the monthly Customer and Demand Charges. The monthly Demand Charge shall be not less than the charge for 25% of the maximum on-peak demand established during the preceding 11 months.

Daily time periods will be based on Pacific Standard Time and are defined as follows:

On-peak: 12:00 noon to 6:00 p.m. summer weekdays except holidays
5:00 p.m. to 10:00 p.m. winter weekdays except holidays

Mid-peak: 8:00 a.m. to 12:00 noon and 6:00 p.m. to 10:00 p.m. summer weekdays except holidays
8:00 a.m. to 5:00 p.m. winter weekdays except holidays

Off-peak: All other hours.

Off-peak holidays are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas.

For initial implementation of this schedule by the Company, winter shall consist of the billing periods for the six regularly scheduled monthly billings beginning with the first regularly scheduled billing ending after November 14, 1977. Thereafter, regularly scheduled monthly billings shall include six summer billing periods followed by six winter billing periods. In no event will winter include scheduled billing periods ending after May 31 of any year.

(Continued)

(To be inserted by utility)	Issued by	(To be inserted by Cal. P.U.C.)
Advice Letter No. 478-E	Edward A. Myers, Jr (Name)	Date Filed December 27, 1978
Decision No. 89711, 89783		Effective January 1, 1979
	Vice President (Title)	Resolution No.

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5148-E

Cancelling Revised Cal. P.U.C. Sheet No. 5050-E

Schedule No. TOU-8

GENERAL SERVICE — LARGE

(Continued)

SPECIAL CONDITIONS

1. **Voltage:** Service will be supplied at one standard voltage.

2. **Maximum Demand:** Maximum demands shall be established for the daily on-peak, mid-peak, and off-peak periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments to be supplied by the Company, during any 15-minute metered interval, but not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule No. 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

3. **Billing Demand:** Separate billing demands for the on-peak, mid-peak, and off-peak daily time periods shall be established for each monthly billing period. The billing demand for each daily time period shall be the maximum demand for that daily time period occurring during the respective monthly billing period.

4. **Voltage Discount:** The charges before adjustments will be reduced by 1% for service delivered and metered at a nominal voltage of 33,000 volts, and by 2% for service delivered and metered at a nominal voltage of 66,000 volts or over.

5. **Power Factor Adjustment:** The charges will be adjusted each month for reactive demand. The charges will be increased by 20 cents per kilovar of maximum reactive demand imposed on the Company in excess of 20% of the maximum number of kilowatts.

The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering to be supplied by the Company during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

6. **Temporary Discontinuance of Service:** Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

7. **Contracts:** An initial three-year facilities contract may be required where applicant requires new or added serving capacity exceeding 2,000 kVA.

8. **Energy Cost Adjustment:** The rates above are subject to adjustment as provided for in Part G of the Preliminary Statement. The applicable energy cost adjustment billing factors and fuel collection balance adjustment billing factor set forth therein will be applied to all kWh billed under this schedule.

9. **Tax Change Adjustment:** The rates above are subject to adjustment as provided for in Part I of the Preliminary Statement. The applicable tax change adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

10. **Conservation Load Management Adjustment:** The rates above are subject to adjustment as provided for in Part J of the Preliminary Statement. The applicable conservation load management adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

(To be inserted by utility)	Issued by	(To be inserted by Cal. P.U.C.)
Advice Letter No. 478-E	Edward A. Myers, Jr. (Name)	Date Filed December 27, 1978
Decision No. 89711, 89783		Effective January 1, 1979
	Vice President (Title)	Resolution No.

			VARIABLE NAME
ENTER IN CARD 42:			
Columns:	1 thru 10:	the ratio of sale price to purchase price of electricity. Assumes excess electricity generated can be sold back to the utility company, and utility will reimburse for energy, but not demand and meter charges.	SALPUR

Data card sample on page 109.

For specific information on the life cycle cost analysis, refer to the Department of the Navy letter dated 27 July 1978, and related figures on pages 76 thru 79.

ENTER IN CARD 43:

			VARIABLE NAME
Columns:	1 thru 5:	the year for which the present value costs will be computed.	NOWYR
	6 thru 10:	the year the installation will be completed.	INSTYR
	11 thru 15:	the year the escalation rate will change from short-term to long-term. This is normally 25 years. Refer to figures on page 80.	JYRCHN
	16 thru 20:	the number of years of the economic life. Refer to figures on page 81.	LIFE

Data card sample on page 110.

For specific information on the short-term escalation rate, refer to item 9 on page 78.

For specific information on the long-term differential escalation rate, refer to item 10 on page 79.

ENTER IN CARD 44:

Columns:	1 thru 10:	the short-term escalation rate of the fuel price for the gas turbine.	FESTGT
	11 thru 20:	the long-term differential escalation rate of the fuel price for the gas turbine.	FELTGT
	21 thru 30:	the short-term escalation rate of the fuel price for the diesel engine.	FESTDS
	31 thru 40:	the long-term differential escalation rate of the fuel price for the diesel engine.	FELTDS
	41 thru 50:	the short-term escalation rate of the fuel price for the steam turbine.	FESTST
	51 thru 60:	the long-term differential escalation rate of the fuel price for the steam turbine.	FELTST
	61 thru 70:	the short-term escalation rate of the fuel price for the auxiliary fired boiler.	FESTBL
	71 thru 80:	the long-term differential escalation rate of the fuel price for the auxiliary fired boiler.	FELTBL

Data card sample on page 111.

ENTER IN CARD 45:

Columns:	1 thru 10:	the short-term differential escalation rate for operating and maintenance.	OMESCS
	11 thru 20:	the long-term differential escalation rate for operating and maintenance.	OMESCL
	21 thru 30:	the short-term escalation rate for electricity.	ELESST
	31 thru 40:	the long-term differential escalation rate for electricity.	ELESLT
	41 thru 50:	the discount factor. For Navy application it is mandated as 10% (0.10).	DISC

Data card sample on page 111.

Ser [illegible]
27 Jul 1978

From: Chief of Naval Operations

Subj: Energy Conservation Investment Program Guidance

Ref: (a) NAVFACINST 11010.[illegible] of 9 Nov 1973
(b) NAVFACINST 11010.[illegible] of 28 Mar 1975

Encl: (1) Energy Conservation Investment Program (ECIP) Criteria

1. The conservation of energy continues to be an important national goal, one strongly supported by the Navy. This support is evidenced by the allocation of significant resources for a dedicated military construction program created to reduce energy consumption at Naval shore activities through the retrofit of existing facilities. $53 million, $55 million, and $50 million have been identified for this ECIP program in fiscal years 81, 82, and 83 respectively.

2. The ECIP program can make a real contribution toward meeting this national goal, but only through the wholehearted support of the Major Claimants in the development of meaningful projects for the program. Projects funded under this program are those which return the maximum reduction in energy consumption for the dollar invested. The attention and imagination of the addressees in developing and submitting projects in support of this program is solicited. Since the projects will be funded under the dedicated program they will not decrease a Major Claimants' share of the regular MILCON.

3. Submission of projects in accordance with references (a) and (b) as expeditiously as possible is encouraged to insure funding consideration in the earliest programming cycle. Criteria for candidate ECIP projects is forwarded as enclosure (1).

R. E. NORTBERG
By direction

Distribution:
SNDL
21A (Fleet Commanders in Chief)
A3 (Chief of Naval Operation)
A4A (Chief of Naval Material)

ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP) CRITERIA

The ECIP shall include military construction projects which conserve energy and meet the following criteria:

1. ECIP projects must be cost-effective based on a savings-to-investment ratio greater than one utilizing a life cycle cost analysis.

2. Each project must have an energy savings-to-investment ratio of at least the following values for annual million BTUs (MBTUs) saved per $1000 of total investment: FY-80, 22; FY-81, 20; FY-82, 19; FY-83, 18; and FY-84, 17.

3. Projects are restricted to the retrofit of existing facilities. New construction and total replacement of facilities will not be included in the ECIP.

4. ECIP projects should combine similar work in various buildings with different category codes in order to reduce contract administration costs. An individual project may also combine dissimilar work of different construction trades. When a basewide ECIP project affects more than one claimant, the host activity or lead activity or public works center should prepare and sponsor the project.

5. Projects shall be supported with engineering calculations in sufficient detail to allow validation of energy savings. Most projects will also require supplementary sheets showing such calculations as changes in insulation "U" factors, heat loss rates, and kilowatt demand reductions.

6. Actual fuel heating value rates should be used when known. If not known, the following conversion factors will be used to permit standardized project evaluation comparisons:

Distillate Fuel Oil	138,700 BTU/gal
Residual Fuel Oil	150,000 BTU/gal
Natural Gas	1,031,000 BTU/1000 cu.ft.
LPG, Propane, Butane	95,500 BTU/gal
Bituminous Coal	24,580,000 BTU/Short Ton
Purchased Steam	1,390 BTU/lb
Electrical Source Fuel	11,600 BTU/KWH

Enclosure (1)

ENCL (1) TO CNO SER 44/720848 OF 27 Jul 1978

7. Boiler efficiencies should be included in the calculation of savings from reduced steam consumption. The resulting reduction in fuel input and boiler feedwater represent a real cost avoidance when steam consumption is reduced. The "as-consumed" cost of fuel and electricity shall be used in determining energy dollar savings. The energy costs, as reported by each activity in the monthly Defense Energy Information System (DEIS-II) report, are "as-consumed" costs. An 'Activity Rate or Host Rate", which includes overhead and maintenance costs, should not be used for calculating savings. Such costs do not normally change with small percentage reductions in overall steam consumption.

8. When two or more energy projects are programmed for the same facility, the computation of energy savings must indicate which portions of the energy savings would be duplicative.

9. Energy, material, and labor prices should be escalated from current rates to those projected for 30 September of the fiscal year for which the project is submitted for funding. Unless more definitive future prices can be determined or predicted for an individual activity, the following rates are to be used for escalation:

	FY-79	FY-80	FY-81	FY-82	FY-83
Design & Construction	7.0%	6.5%	6.0%	6.0%	6.0%
Operations & Maintenance	6.4%	6.2%	5.6%	5.6%	5.6%
Coal	10.0%	10.0%	10.0%	10.0%	10.0%
Fuel Oil	16.0%	16.0%	14.0%	14.0%	14.0%
Natural Gas & LPG	15.0%	15.0%	14.0%	14.0%	14.0%
Electricity (KWH & KW)	16.0%	16.0%	13.0%	13.0%	13.0%

10. The life cycle cost analysis used to determine the project's savings-to-investment ratio shall utilize a base fiscal year commencing on 1 October following the project's programmed year. The long-term differential escalation rates below are to be used for computing the present worth of recurring annual costs and benefits if more definitive data is not available at individual activities.

Operations & Maintenance 0%	Natural Gas & LPG 8%
Coal 5%	Electricity (KWH & KW) 7%
Fuel Oil 8%	

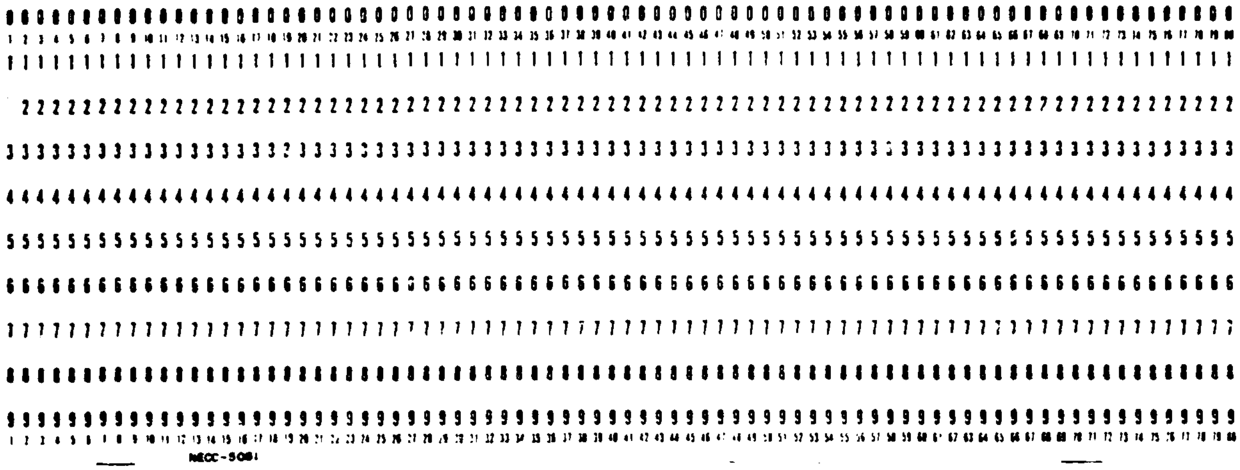
11. The present worth factors for multiplication of recurring annual savings can be selected from the appropriate differential escalation rate column in the DISCOUNT FACTORS table on the next page.

12. Economic life is the period of time over which the life cycle benefits to be gained from a project may reasonably be expected to accrue. As such, the economic life may differ from its physical and technological life. The economic lives below may be used as guides, and ordinarily will not be exceeded.

CATEGORY	ECONOMIC LIFE
BUILDINGS (including insulation, solar screens, heat recovery systems, solar installations, etc.)	25 years
UTILITIES (plants and distribution systems)	25 years
ENERGY MONITORING & CONTROL SYSTEMS	15 years
CONTROLS (thermostats, limit switches, ignition devices, clocks, photo cells, flow controls, sensors, etc. when these constitute the major end item of the project)	15 years
REFRIGERATION COMPRESSORS	15 years

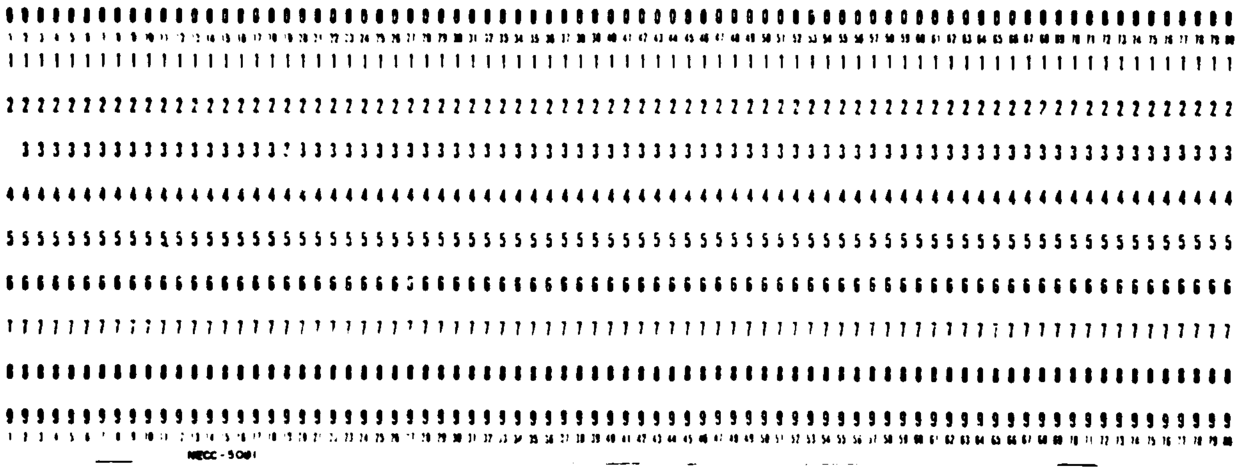
SAMPLES OF
DATA CARD NUMBERS 1 THRU 45

2



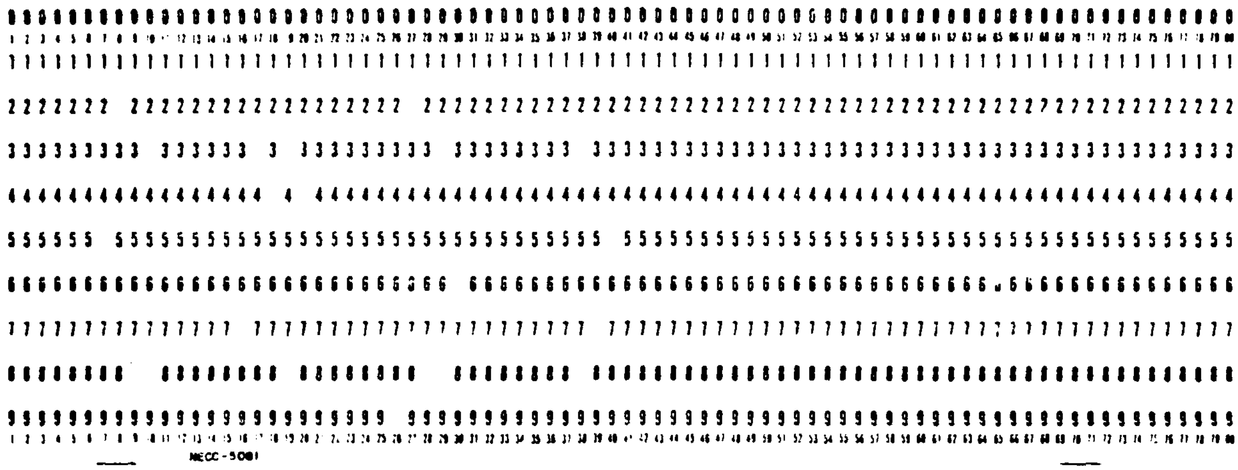
Data Card #1
Control Modes
Variable Name: MDLTR

1



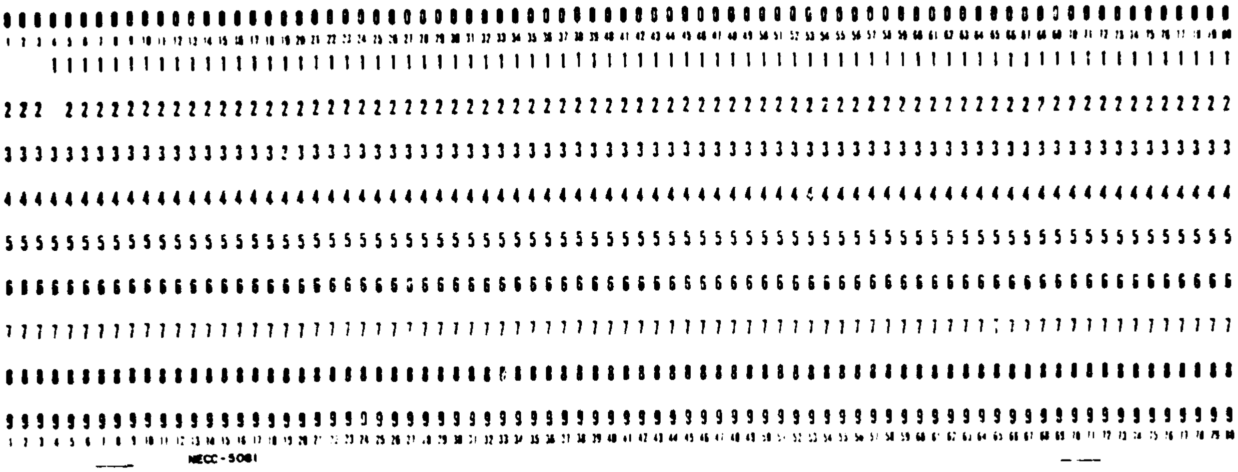
Data Card #2
Reports
Variable Name: IPRNT

528.   734.4   928.6   .75



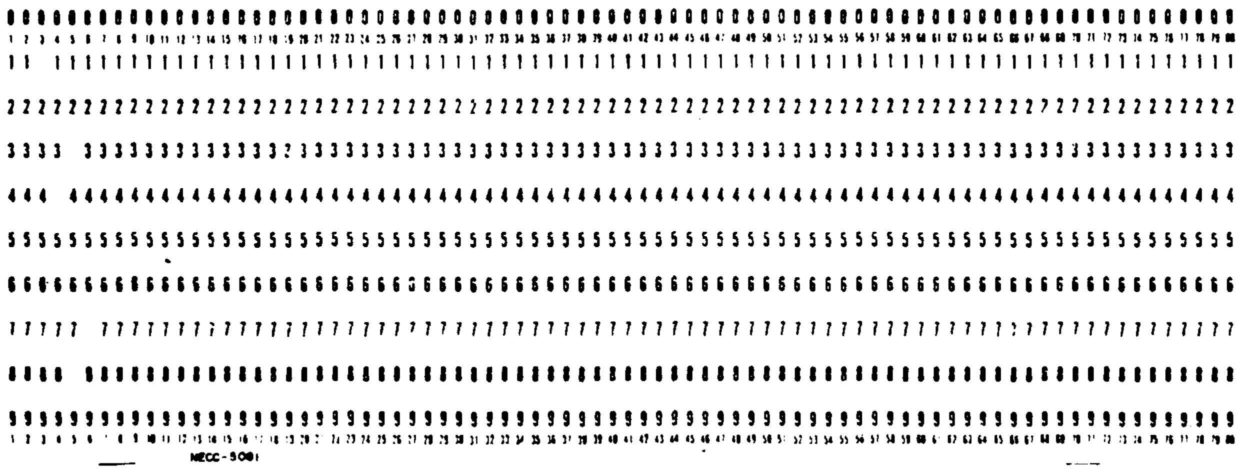
Data Card #3
Information on the Auxiliary Fired Boiler
Variable Names: TBLRFD, TEVP, HLV, BLREF

1112



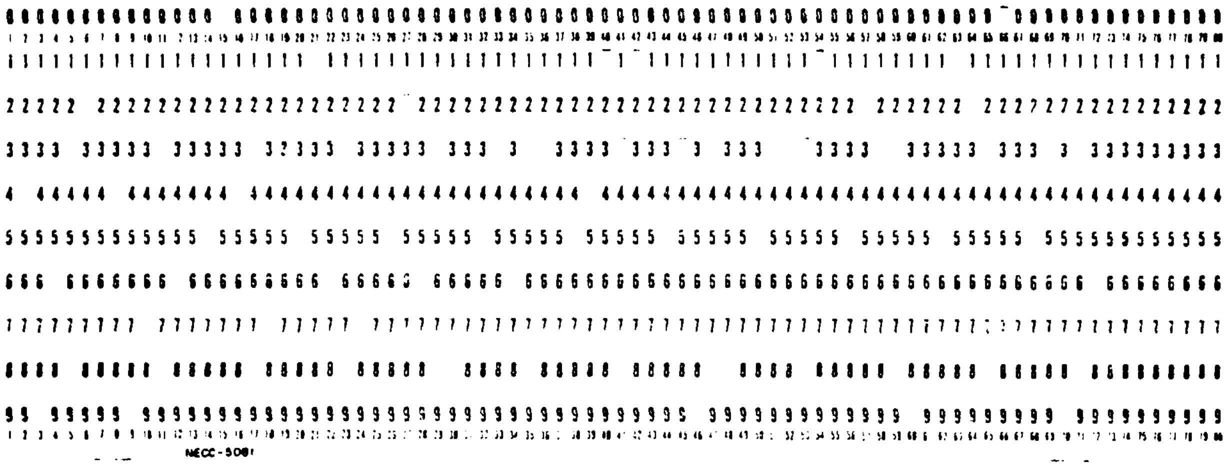
Data Card #4
Total Number of Engines
Variable Names: NUMGT, NUMDSL, NUMSTT, NUBPST

14.7



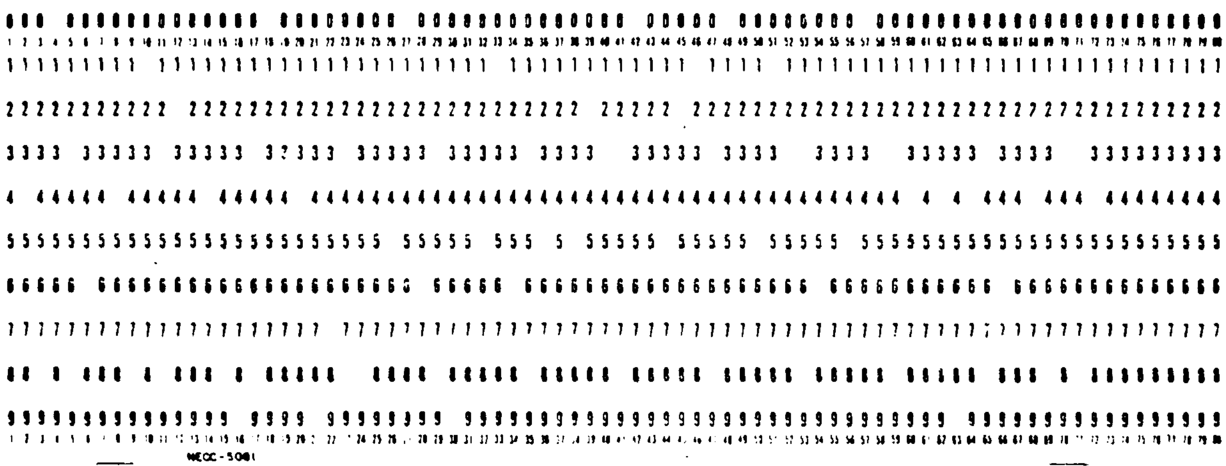
Data Card #5
Ambient Pressure
Variable Name: PAMB

496.2 497.6 504.7 516.7 526.8 536.3 541.1 539.8 533.1 523.9 512.0 539.6



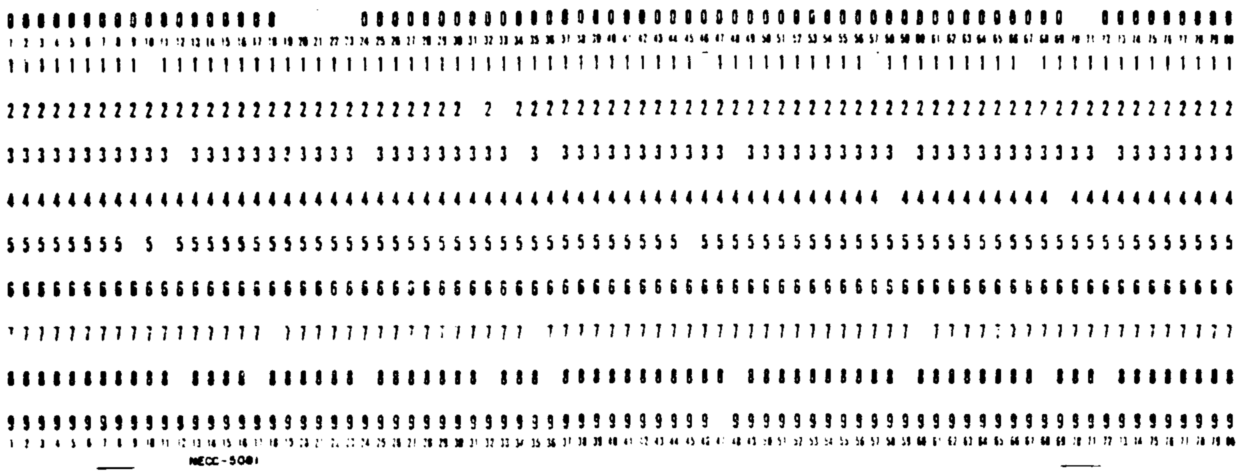
Data Card #6
Maximum Temperature Per Month
Variable Name: TMAX (Month)

480.6 481.2 489.0 497.8 506.9 516.5 523.0 521.0 513.6 503.4 494.6 483.4



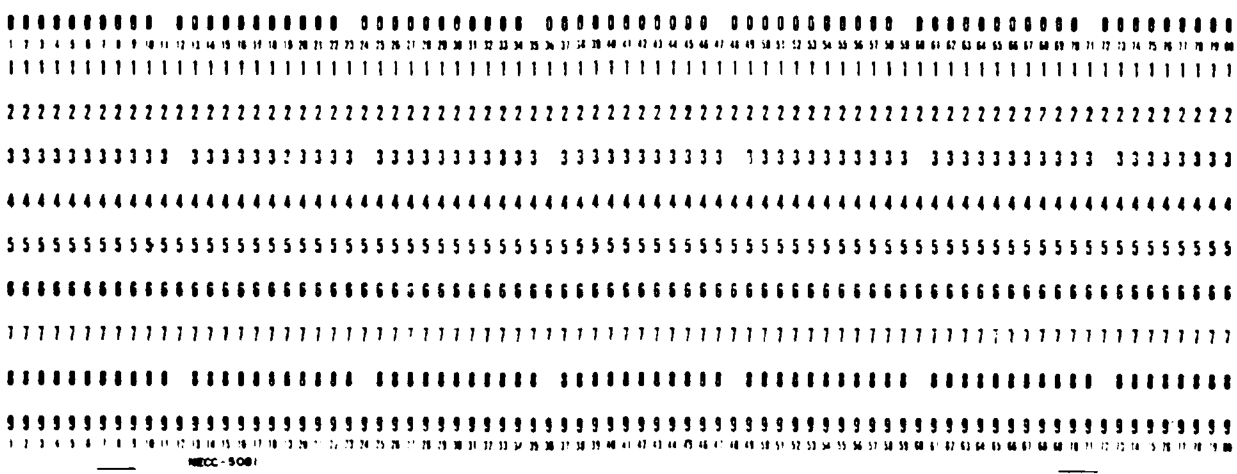
Data Card #7
Minimum Temperature Per Month
Variable Name TMIN (Month)

515.   8700000.   23237.   519.   14.7   19400.



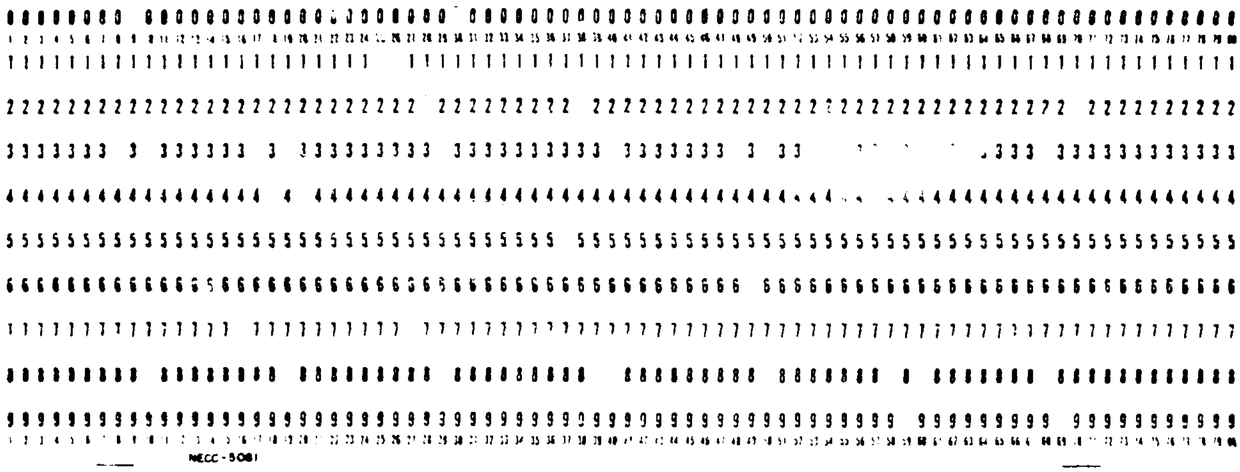
Data Card #8
Design Conditions for the Gas Turbine
Variable Names: ED, QFD, AIRFLD, TAMBD, PAMBD, HV

0.   0.   0.   0.   0.   0.



Data Card #9
Off-Design Condition for the Gas Turbine
Variable Names: EDP, QFP, QFO, TEXHD, TEXHP, TSTACK

30.   734.4   1172.0   528.   36.   .98   .92



Data Card #10

The Heat Recovery Boiler for the Gas Turbine

Variable Names: STMPRE, STMTEP, STMENTH, FETEMP, FEENTH, EFFCTV, EFFNS

AD-A097 870 TWO D ENGINEERING INC OXNARD CA F/G 10/2
CIVIL ENGINEERING LABORATORY COGENERATION ANALYSIS PROGRAM - CE--ETC(U)
MAR 81 P BRADLORD N00123-78-D-0392

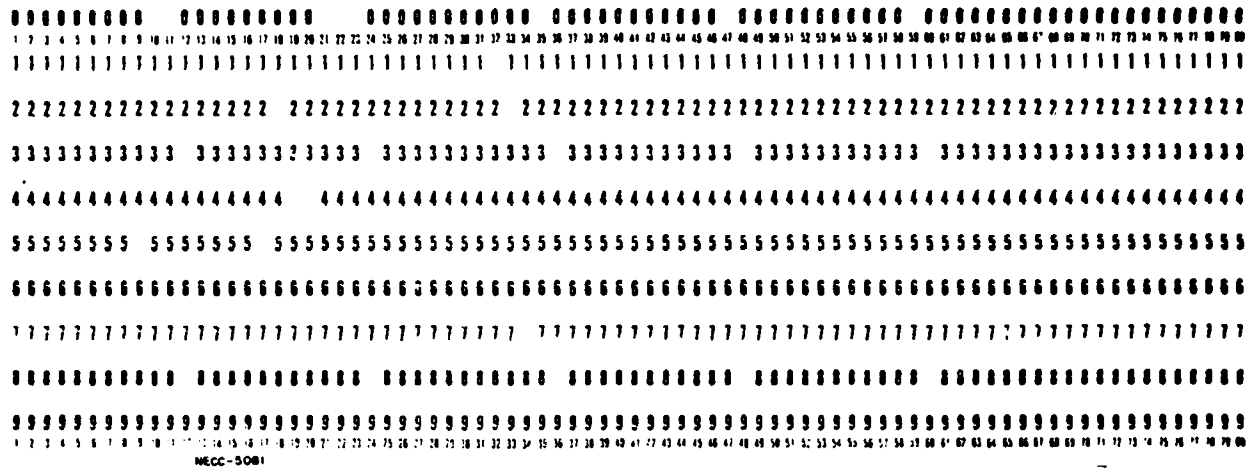
UNCLASSIFIED CEL-CR-81.001 NL

2 of 2

AD A097870

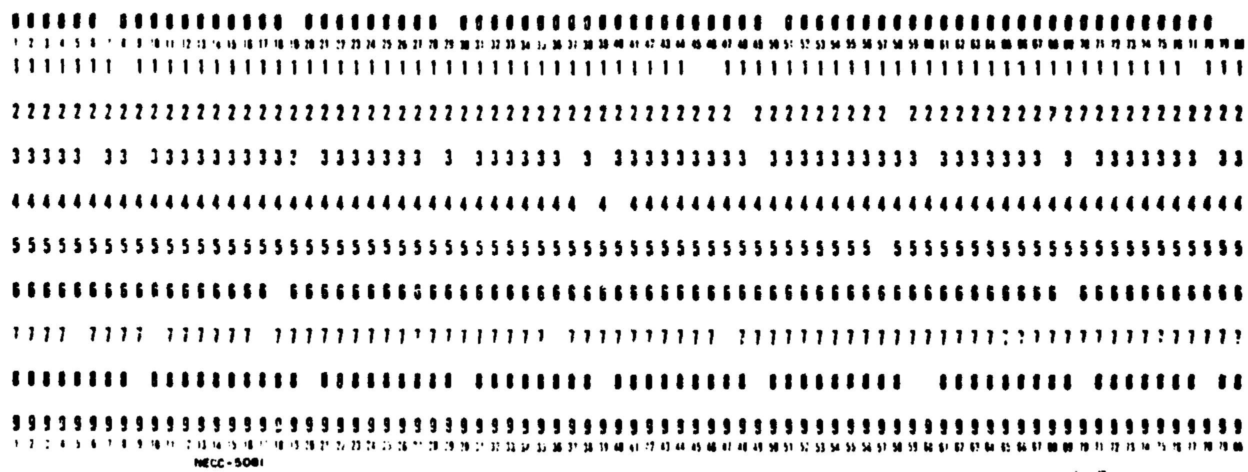
END
DATE
FILMED
5-81
DTIC

500.   5244000.   1270.   0.   0.



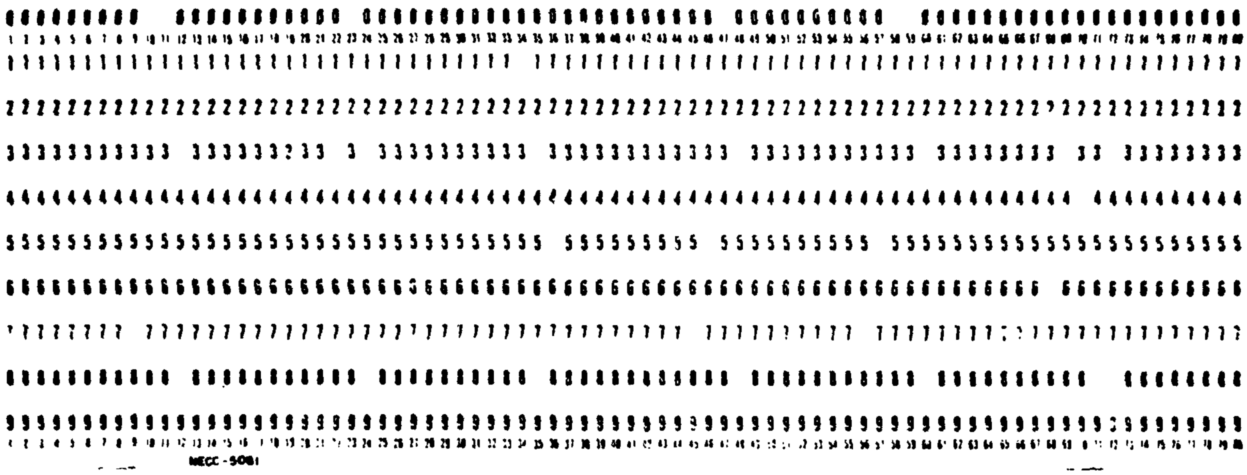
Data Card #11
Design Conditions for the Diesel Engine
Variable Names: ED, QFD, TEXHD, TEXHP, EDP

7301.7   760.   30.   734.4   1172.0   528.   36.   1.00



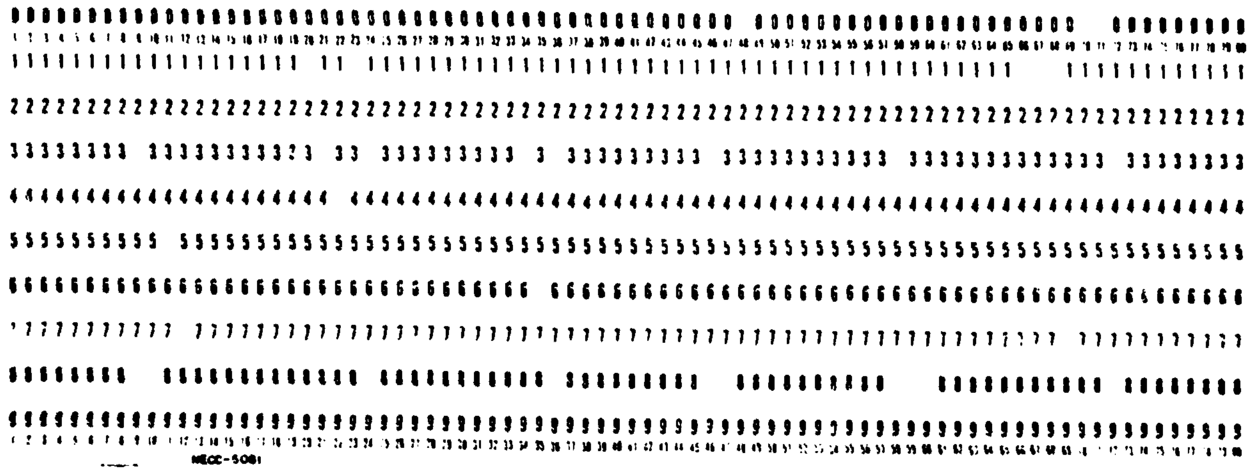
Data Card #12
Heat Recovery Boiler for the Diesel Engine
Variable Names: AIRFLD, TSTACK, STMPRE, STMTEP, STMENTH,
FETEMP, FEENTH, EFFCTV

700. 30. 1.5 750. 7500. 6348.



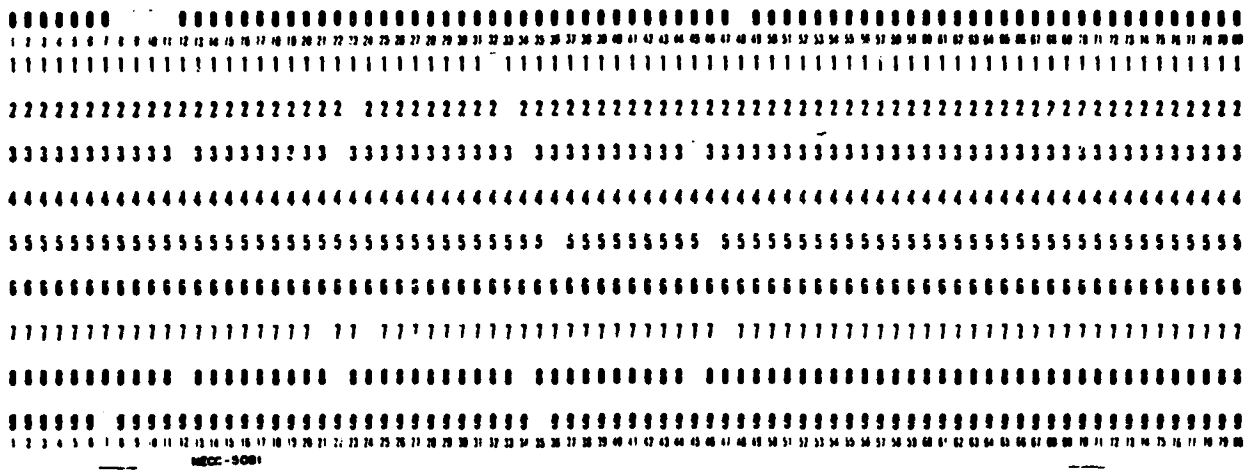
Data Card #13
Auto Extraction Steam Turbine Data
Variable Names: PAMBD, WCD, WTD, TAMBD, EED, ED

.857 1341. 36. .90 .88 111700.



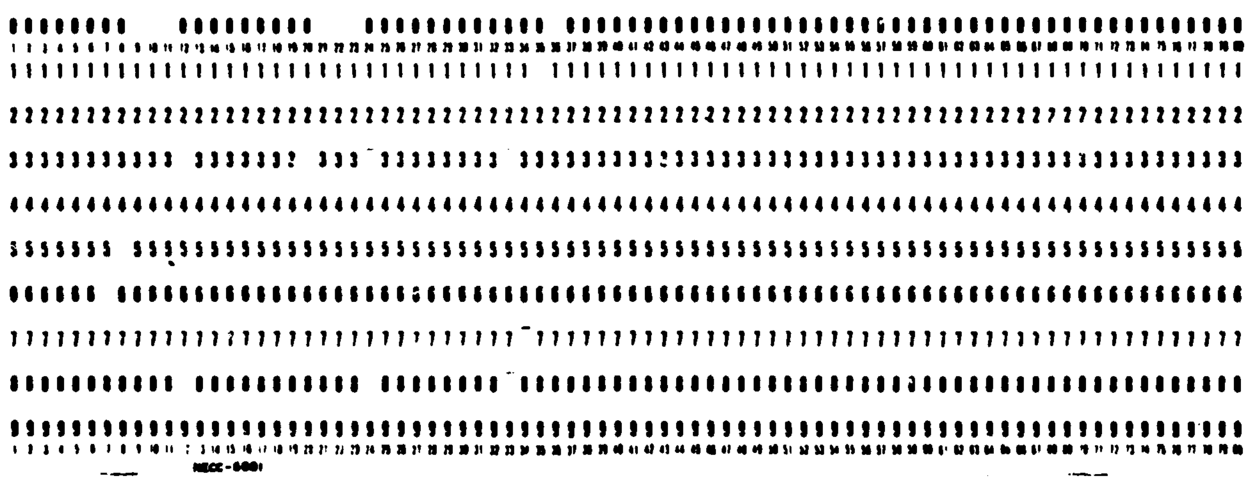
Data Card #14
Auto Extraction Steam Turbine Data
Variable Names: T3LIM, TPNCHD, TEXHD, T3FRC, EFFCTV, THROMAX

90000. 7.27 12.95 .570



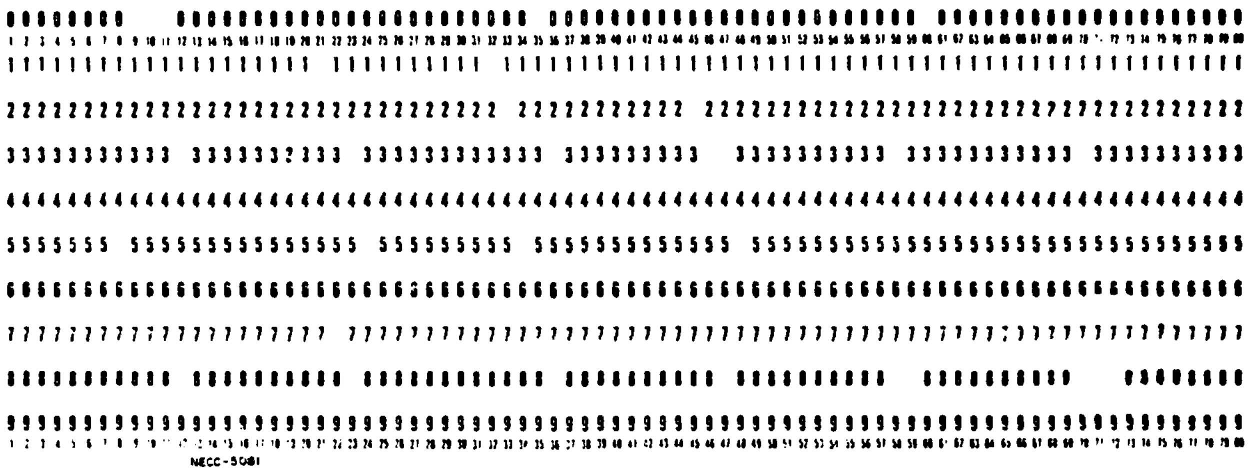
Data Card #15
Auto Extraction Steam Turbine Data
Variable Names: EXPD, T2D, T3D, WC

65000. 3000. .710



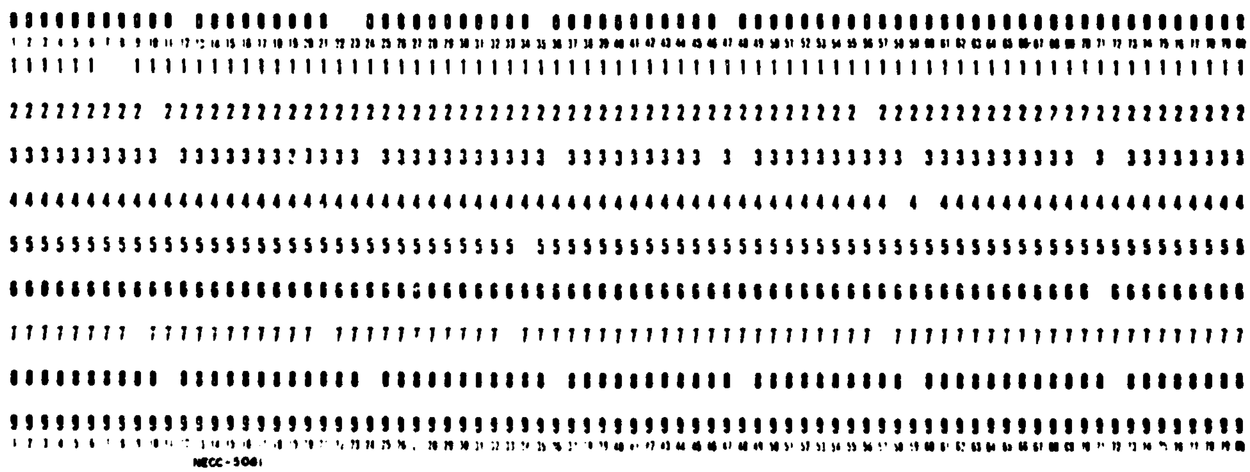
Data Card #16
Auto Extraction Steam Turbine Data
Variable Names: STMD, BLDWND, UA

5000. 17.5 1350. 23.5 .80 .88



Data Card #17
Back Pressure Steam Turbine Data
Variable Names: EED, QFD, EDP, QFP, T3FRC, T3LIM

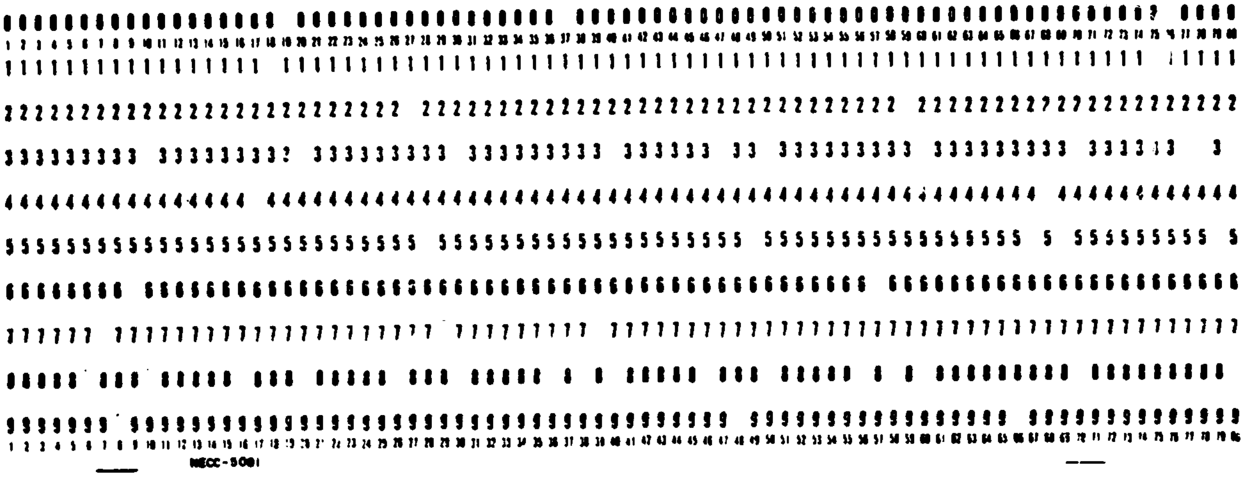
1172.0 700. 750. 30. 274.4 36.



Data Card #18
Back Pressure Steam Turbine Data
Variable Names: TPNCHD, PAMBD, TAMBD, WTD, STMD, TEXHD

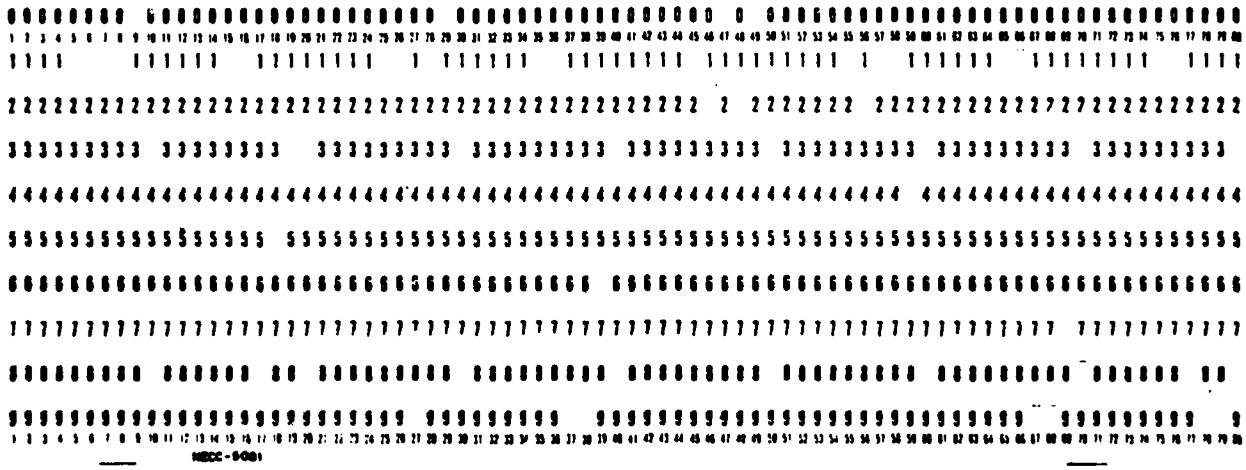
Electrical Load on a Typical Work Day Per Hour in January
Variable Name: ELLD (IHR, Month, Nowork)

8796. 8410. 8257. 8087. 8395. 8682. 9545. 10335.



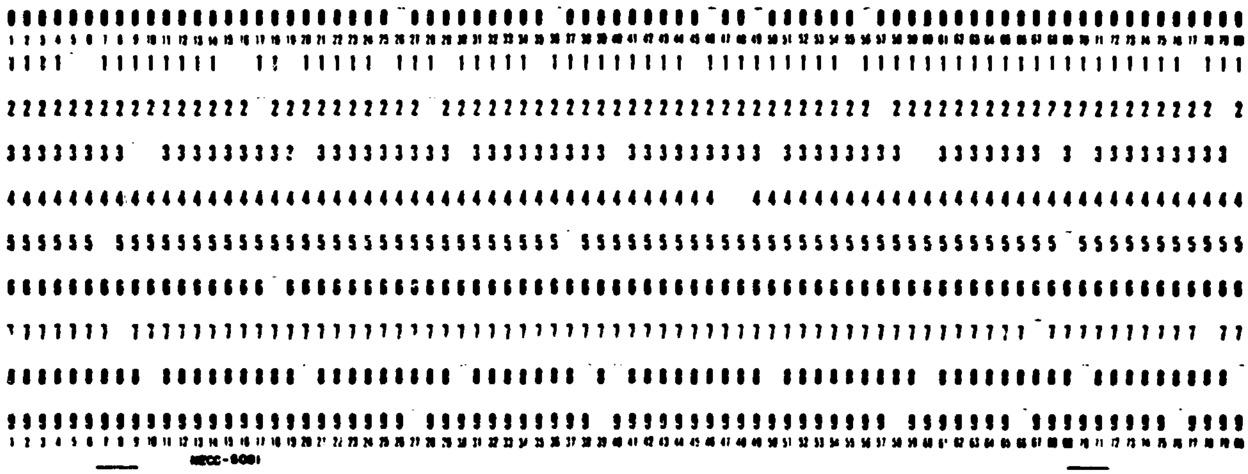
Data Card #19

11110. 11853. 11910. 11996. 12020. 12114. 11997. 11899.



Data Card #20

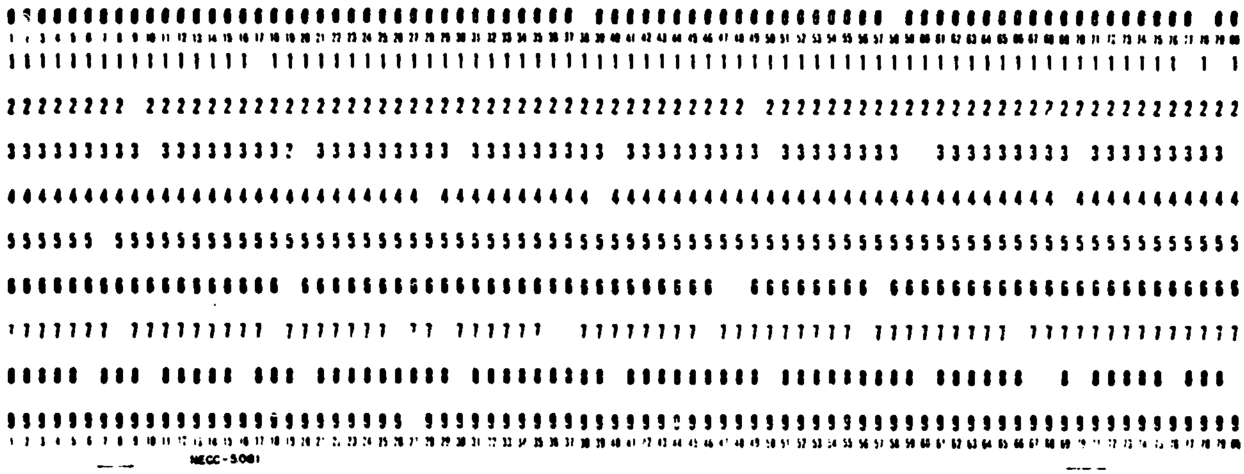
11573. 11261. 10921. 10589. 10440. 10293. 9735. 9172.



Data Card #21

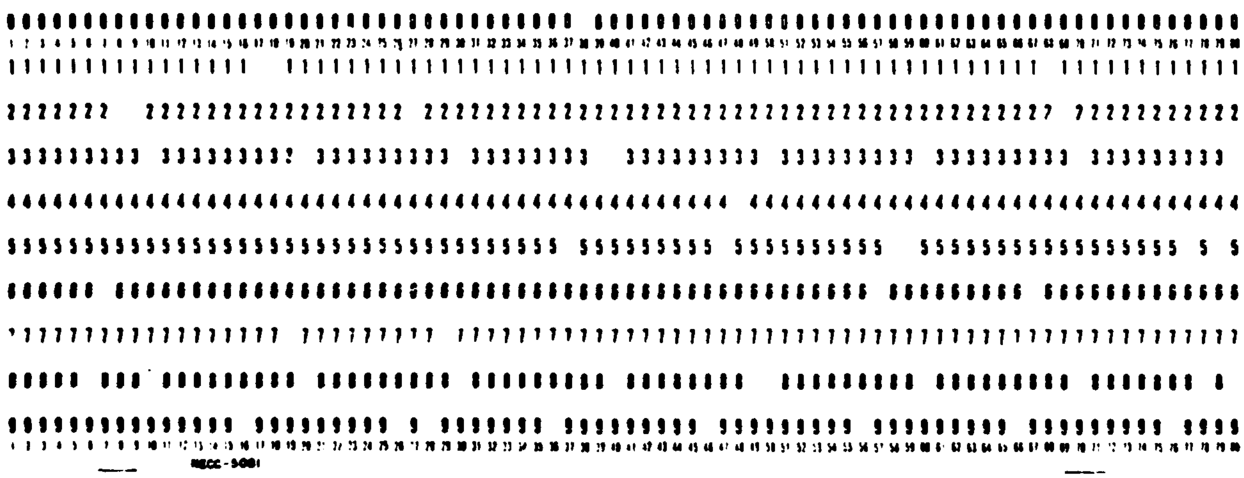
Electrical Load on a Typical Non-Work Day Per Hour in January.
Variable Name: ELLD (IHR, Month, Nowork)

8572. 8176. 7947. 7704. 7660. 7603. 7804. 8101.



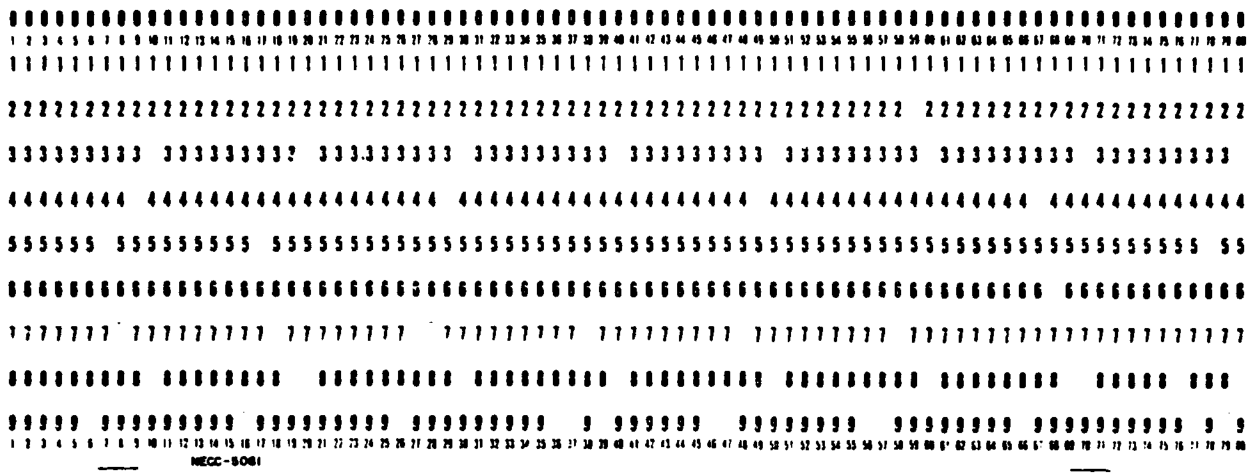
Data Card #22

8622. 9117. 9297. 9503. 9546. 9655. 9612. 9585.



Data Card #23

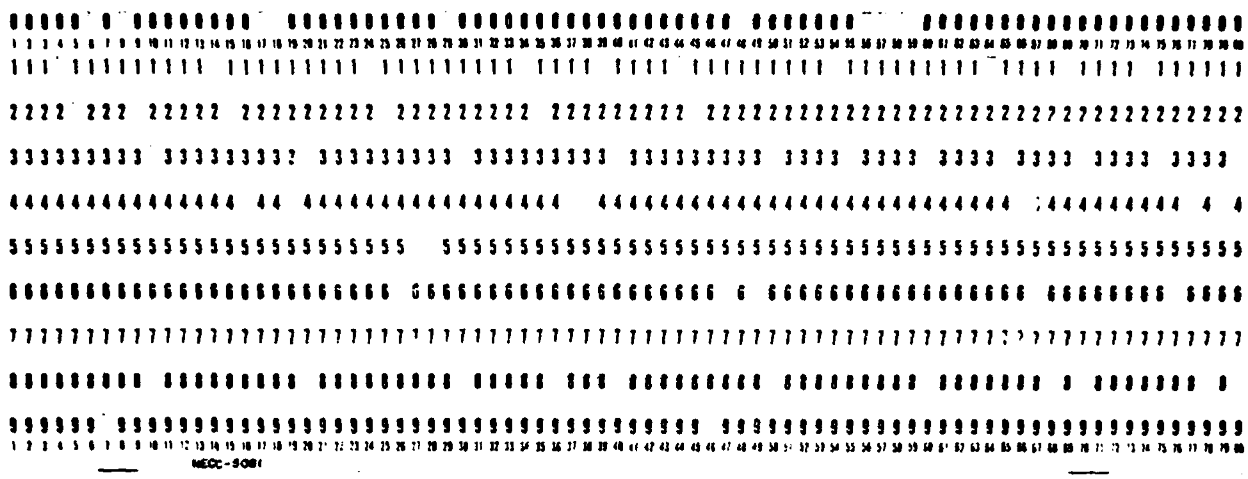
9574. 9578. 9774. 9979. 9974. 9972. 9468. 8959.



Data Card #24

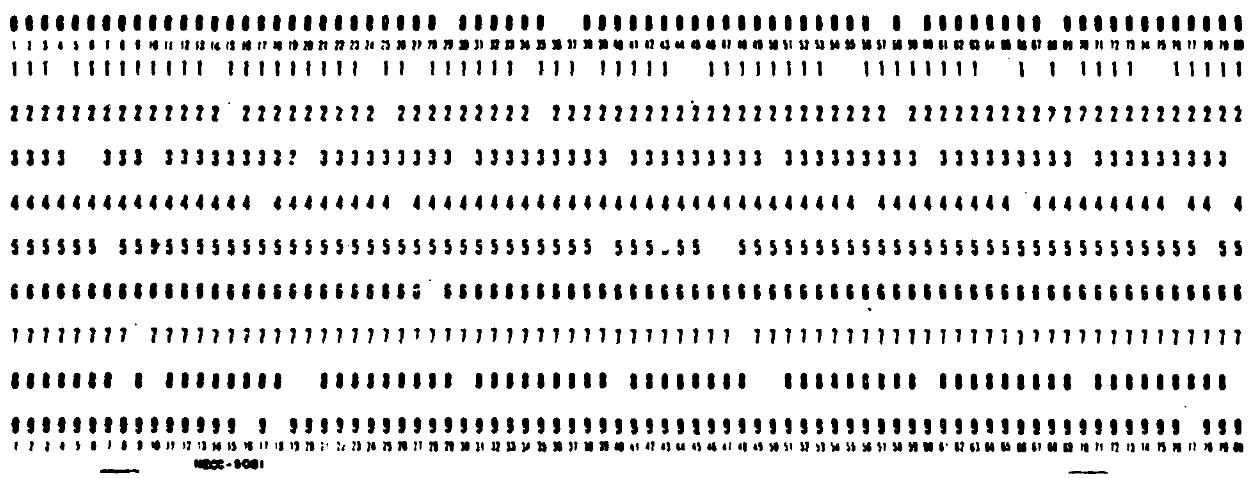
Steam Load on a Typical Work Day Per Hour In January
Variable Name: STMLD (IHR, Month, Nowork)

120902. 124004. 126550. 128441. 129606. 130000. 134631. 136484.



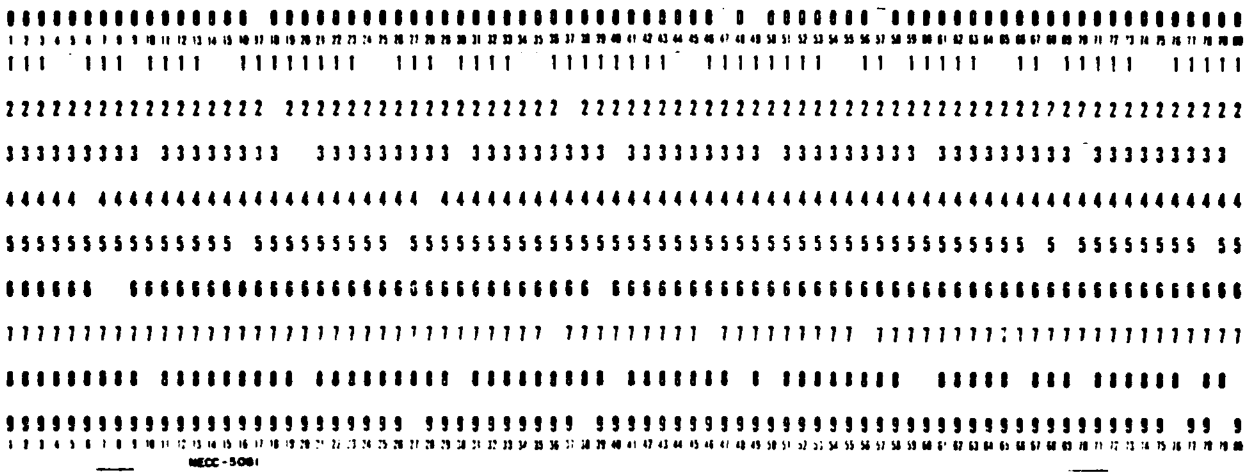
Data Card #25

133587. 129498. 124160. 120015. 115578. 114020. 114101. 114954.



Data Card #26

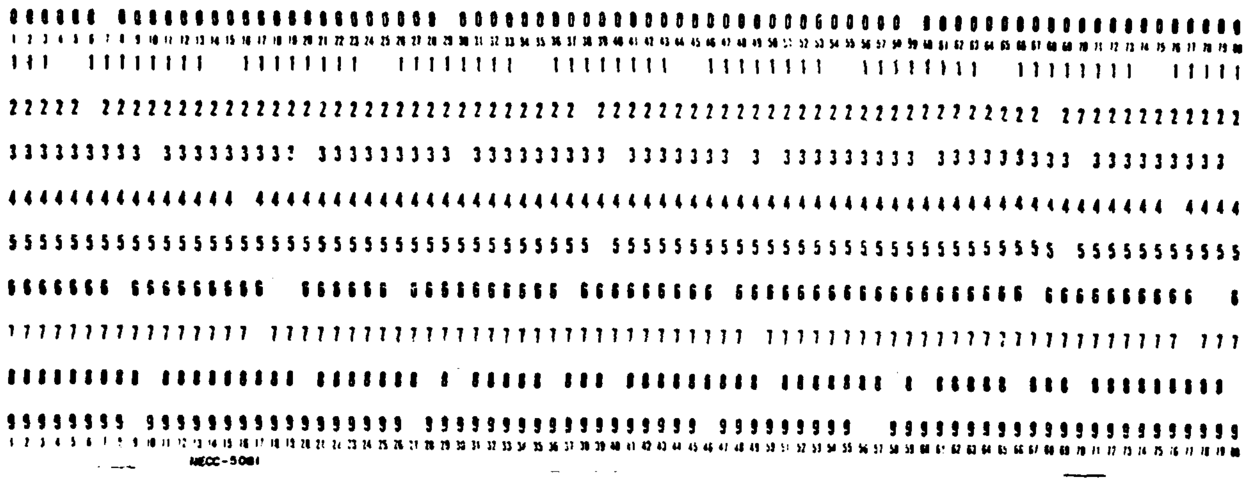
114661. 115023. 115941. 117296. 117380. 117018. 118515. 119859.



Data Card #27

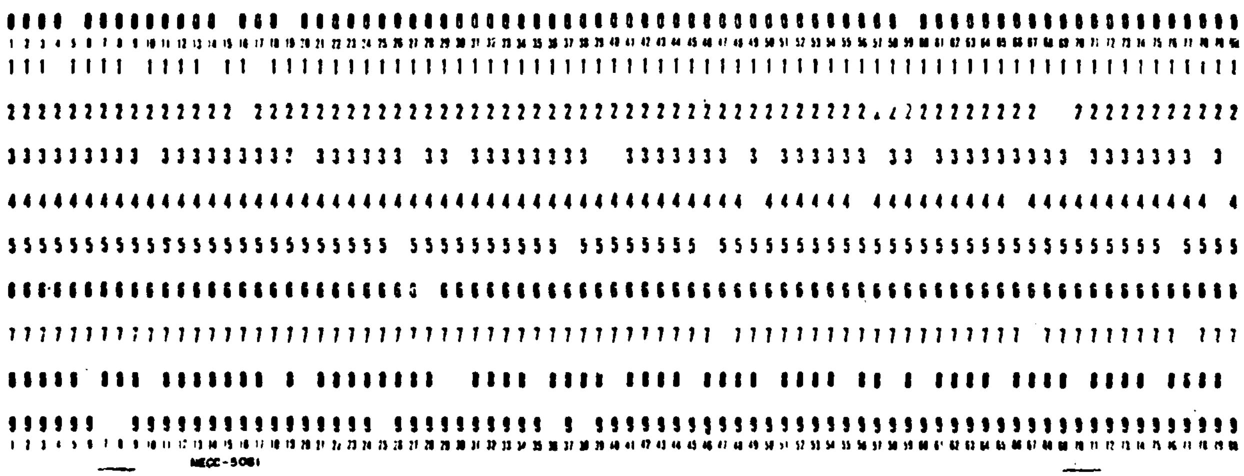
Steam Load on a Typical Non-Workday Per Hour in January
Variable Name: STMLD (IHR, Month, Nowork)

112069. 114766. 116980. 118625. 119637. 119980. 118625. 114766.



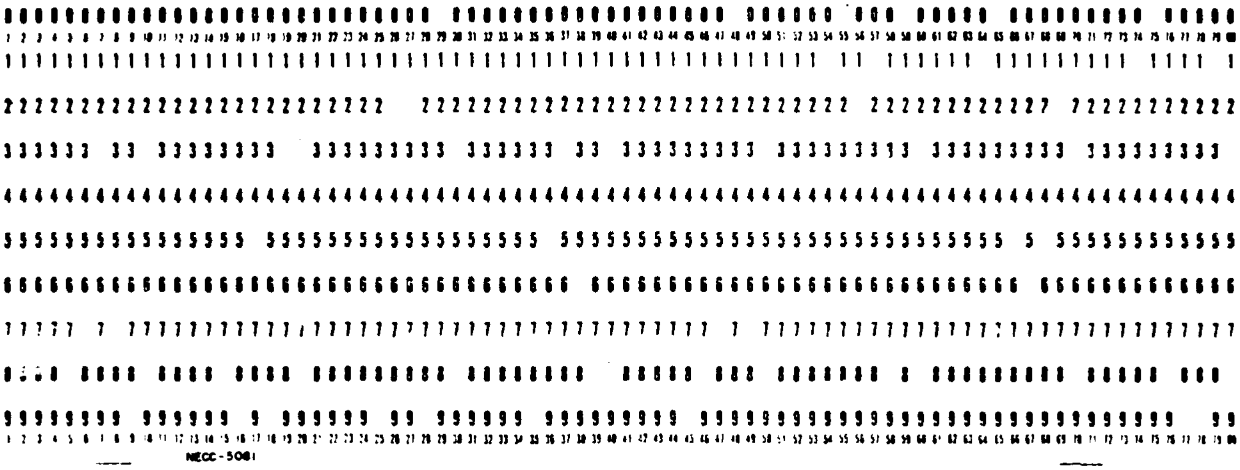
Data Card #28

108991. 102180. 95368. 89593. 85734. 84380. 84722. 85734.



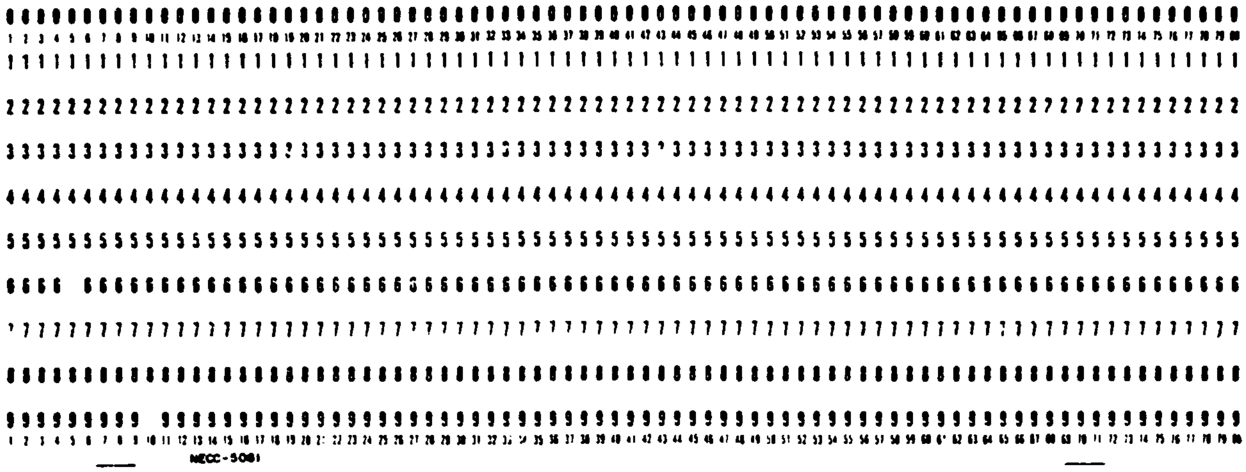
Data Card #29

87379.   89593.   92290.   95368.   98707.   102180.   105652.   108991.



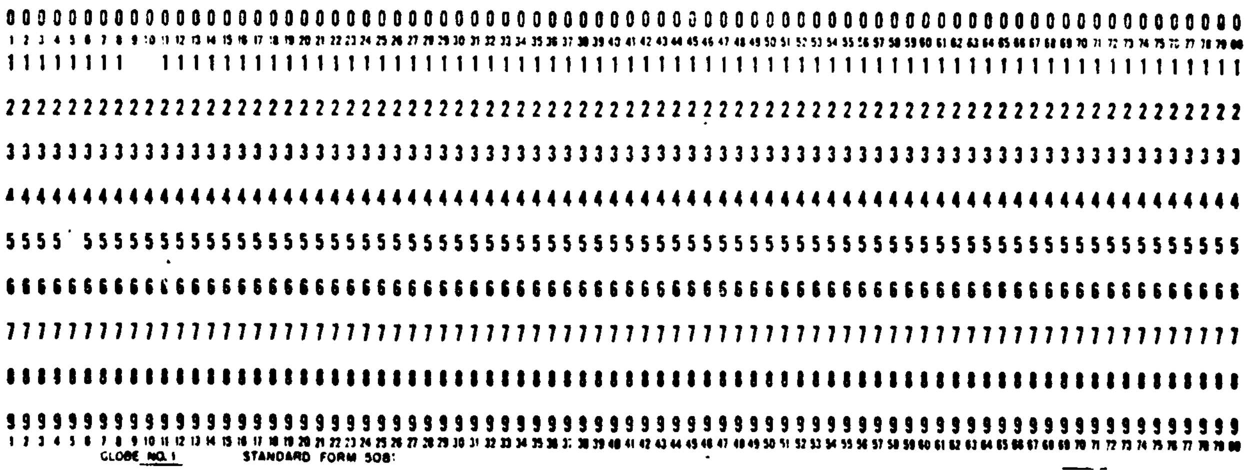
Data Card #30

6 9



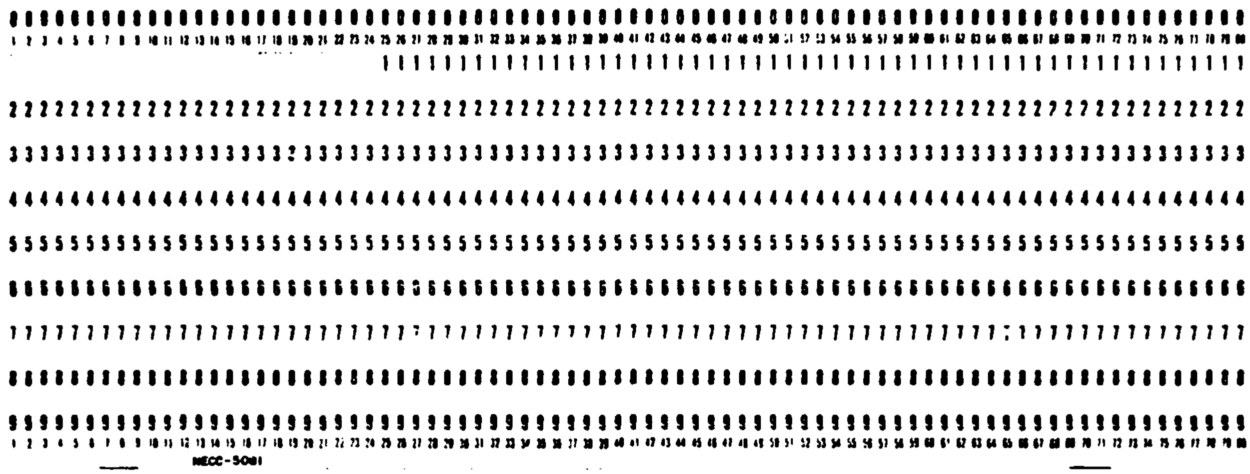
Data Card #31
Months the Rate Changes to Summer and Winter for Demand Pricing
Variable Names: SUMON1, SUMON2

5 11



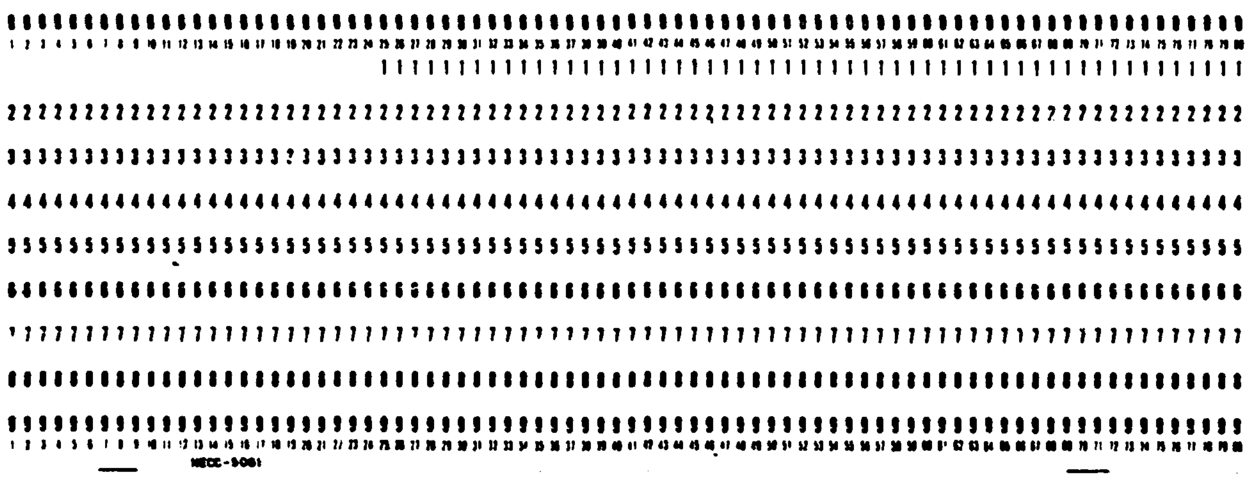
Data Card #31
Months the Rate Changes to Summer and Winter for Demand Pricing
Variable Names: SUMON1, SUMON2

111111111111111111111111



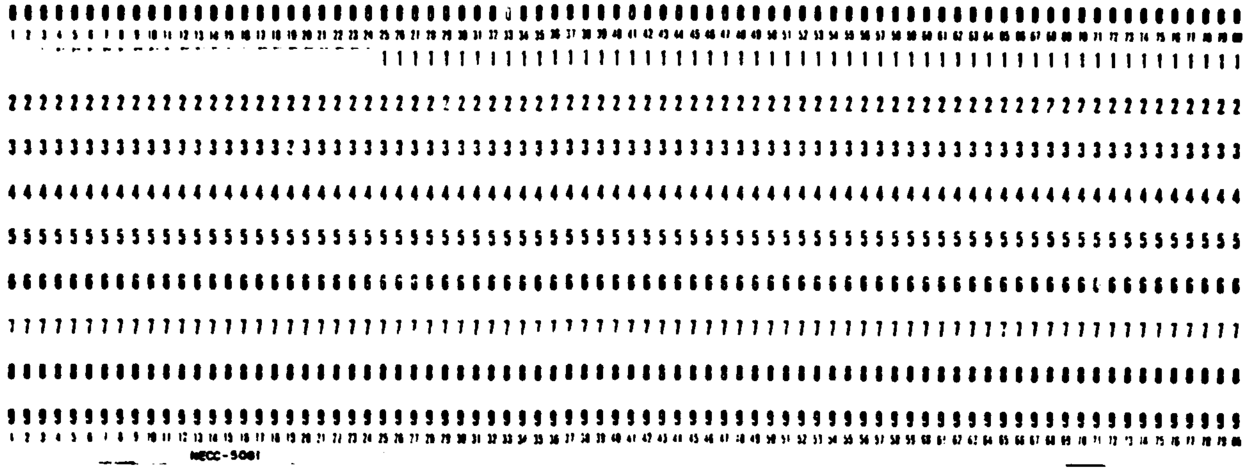
Data Card #32 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Work Day
During the Summer Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

111111111111111111111111



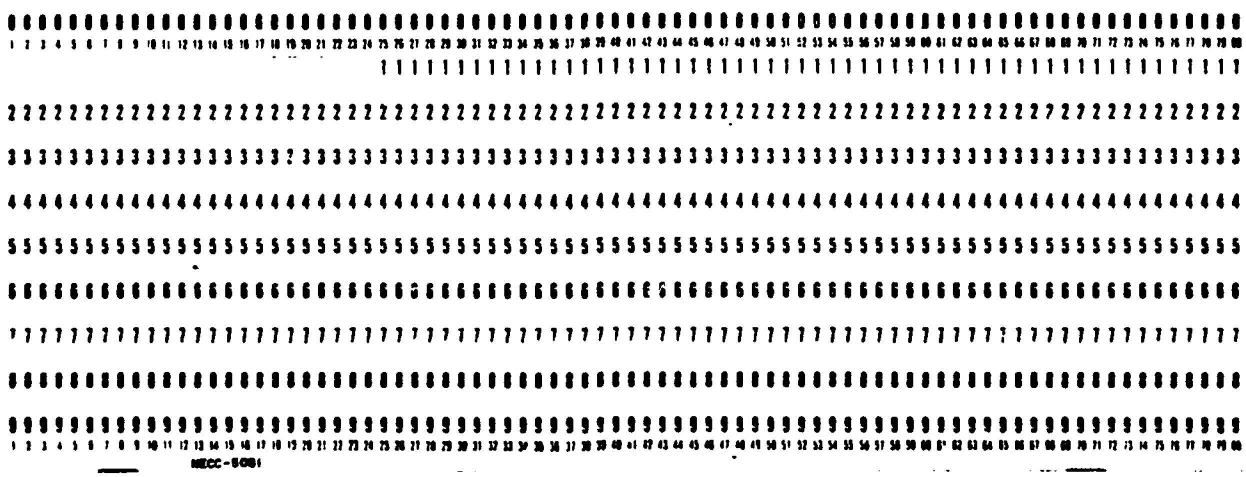
Data Card #33 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Work Day
During the Winter Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

111111111111111111111111

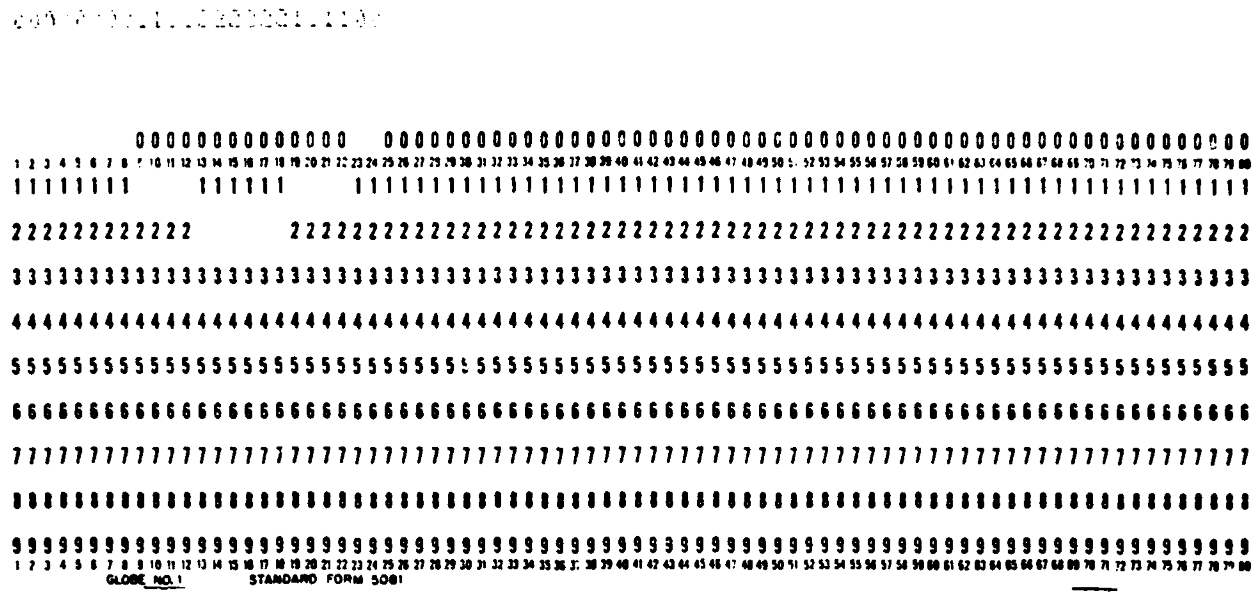


Data Card #34 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Summer Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

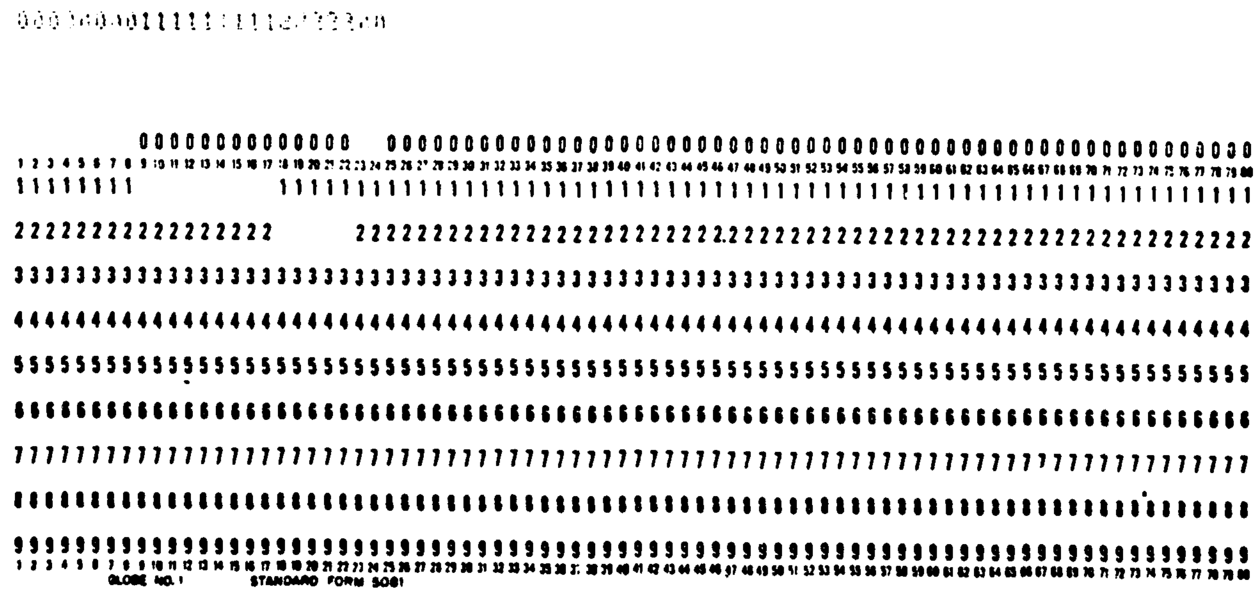
111111111111111111111111



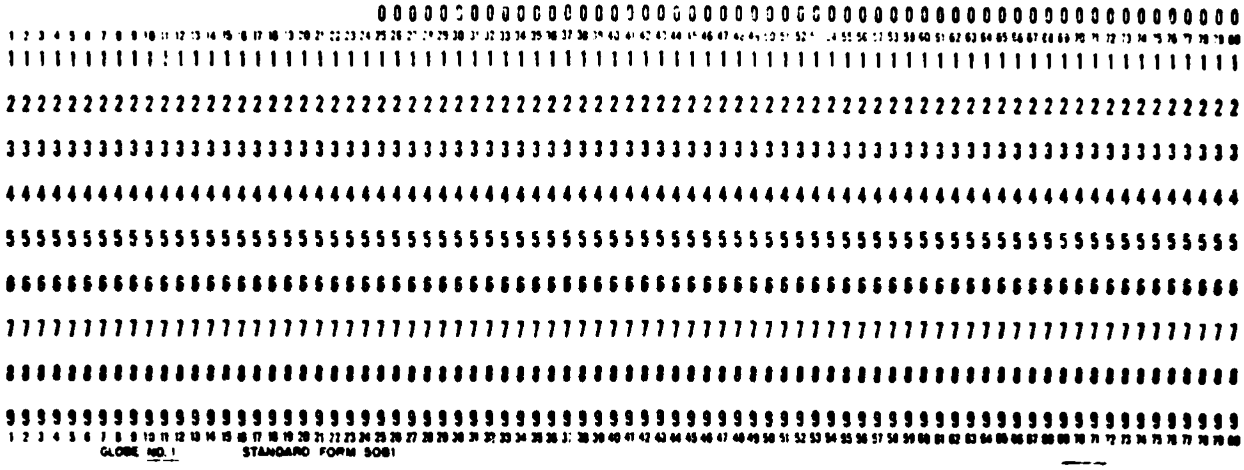
Data Card #35 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Winter Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)



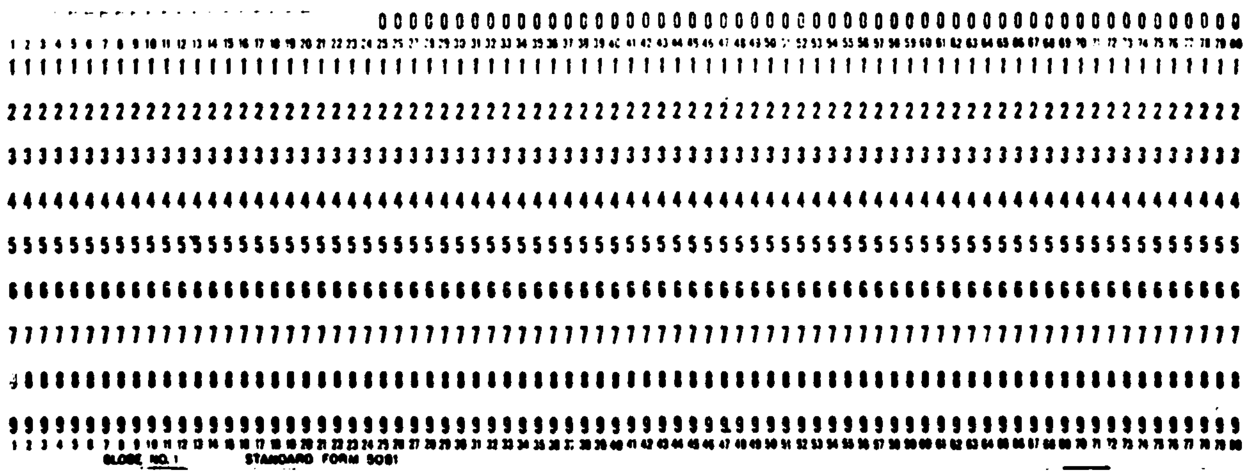
Data Card #32 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Work
Day During the Summer Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)



Data Card #33 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Work
Day During the Winter Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

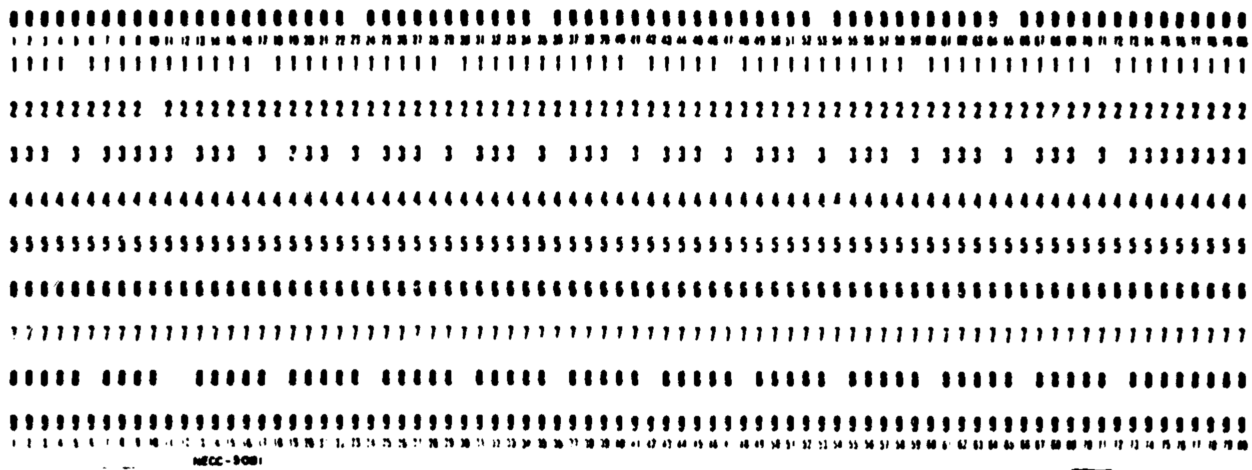


Data Card #34 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Summer Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)



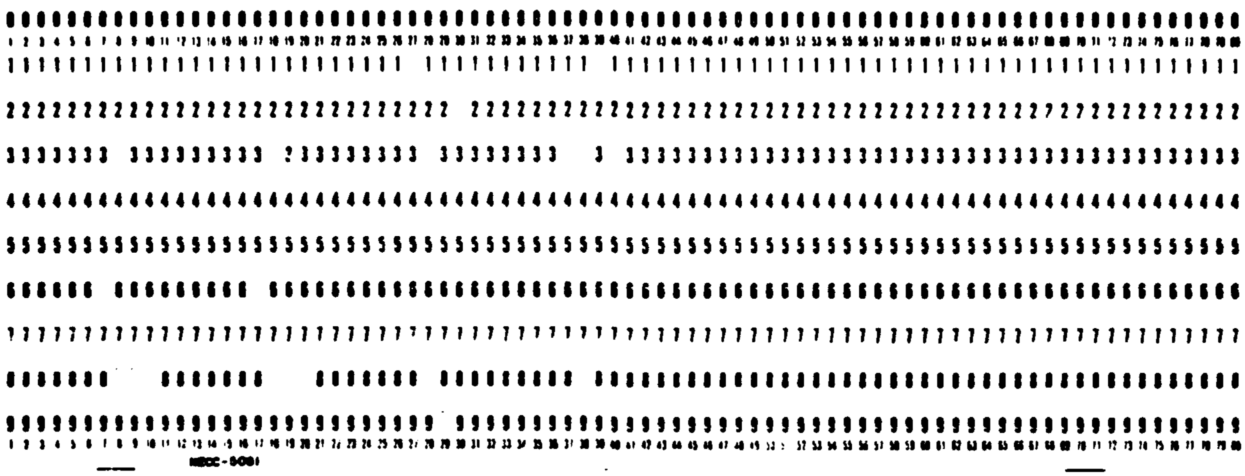
Data Card #35 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Winter Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

31. 28. 31. 30. 31. 30. 31. 31. 30. 31. 30. 31.



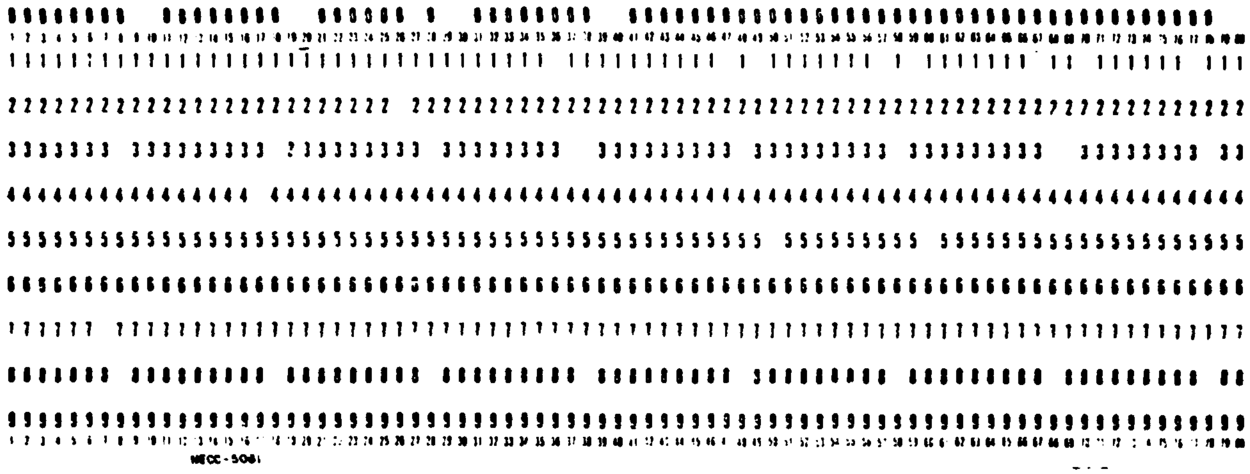
Data Card #36
Number of Days Per Month
Variable Names: PERMO (Month)

6.88 6.88 1.92 3.13



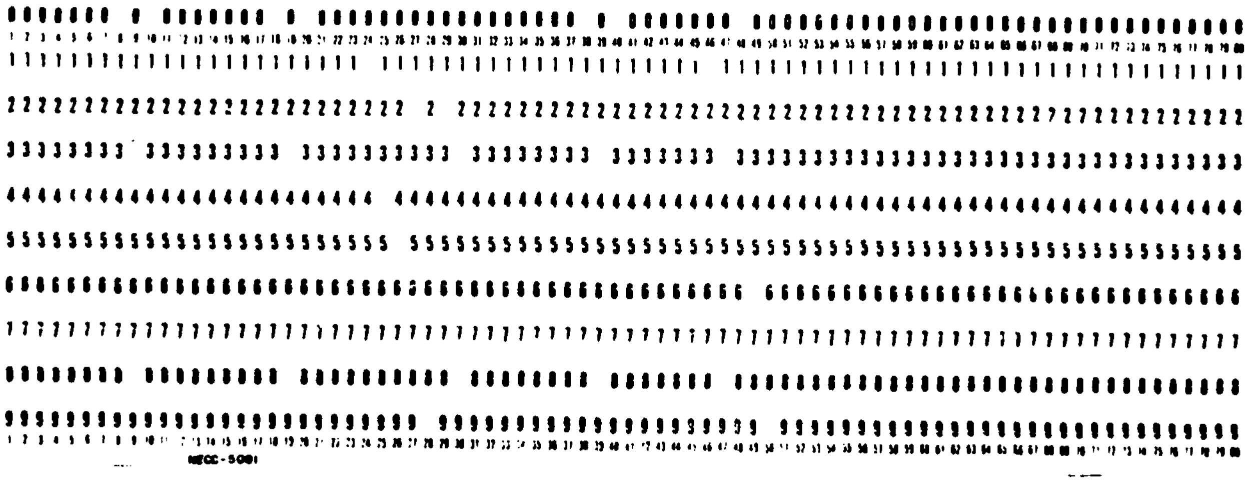
Data Card #37
Current Fuel Prices
Variable Names: GTFLC, DSLFLC, STTFLC, BLRFLC

7.00 4.00 20.00 17.00 1.15 1.15 1.31 1.00



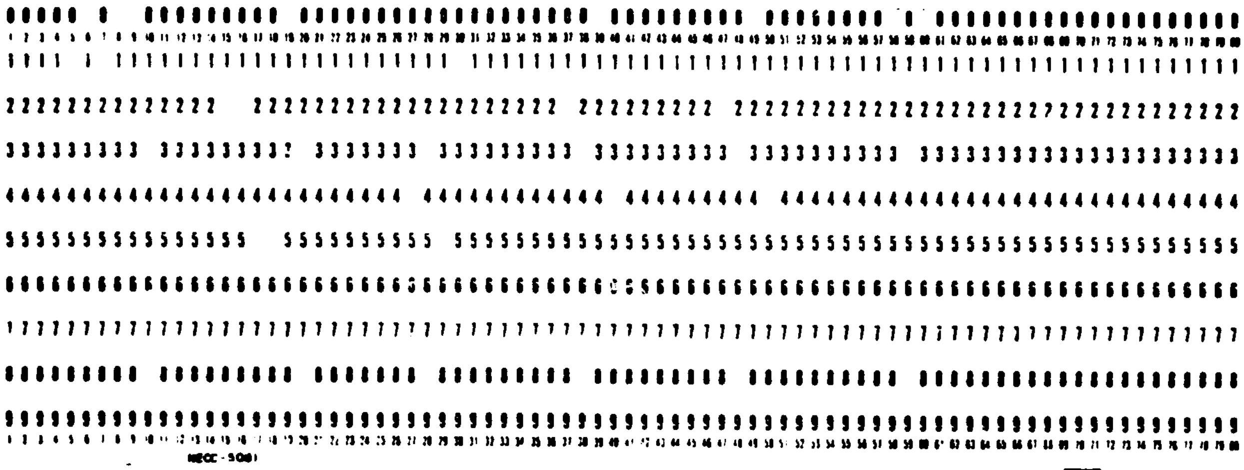
Data Card #38
Operating and Maintenance Costs Per Unit
Variable Names: GTPKOM, GTCGOM, DSPKOM, DSCGOM, STPKOM, STCGOM, BLROM, WASTOM

0.0 0.0 145292. 0.0 1.059



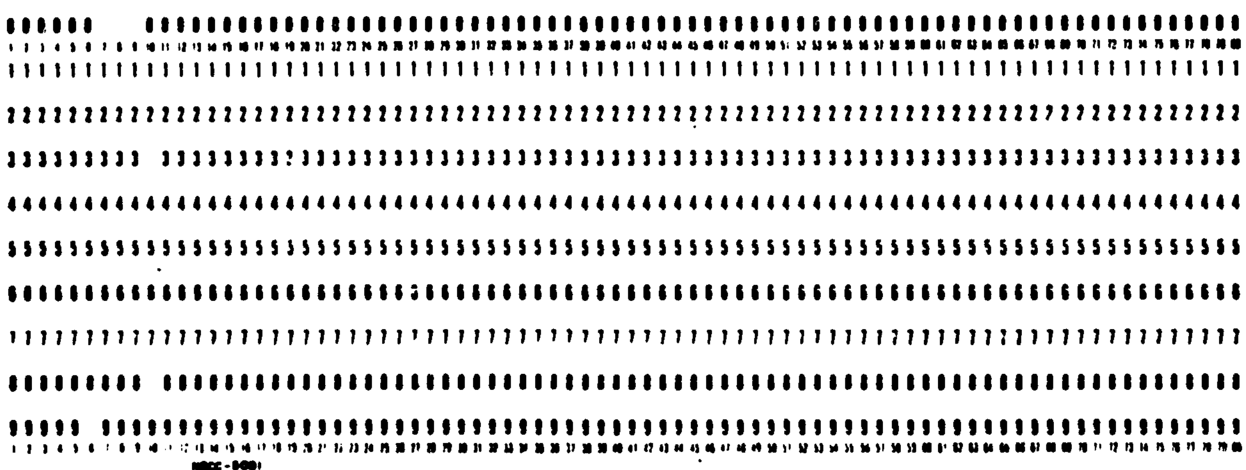
Data Card #39 Time of Day Pricing
Operating and Maintenance Costs Per Month
Variable Names: GTOM, DSOM, STOM, BLFOM, THRSTM

10100.   22550.   4.51   2.04   2.04   0.0

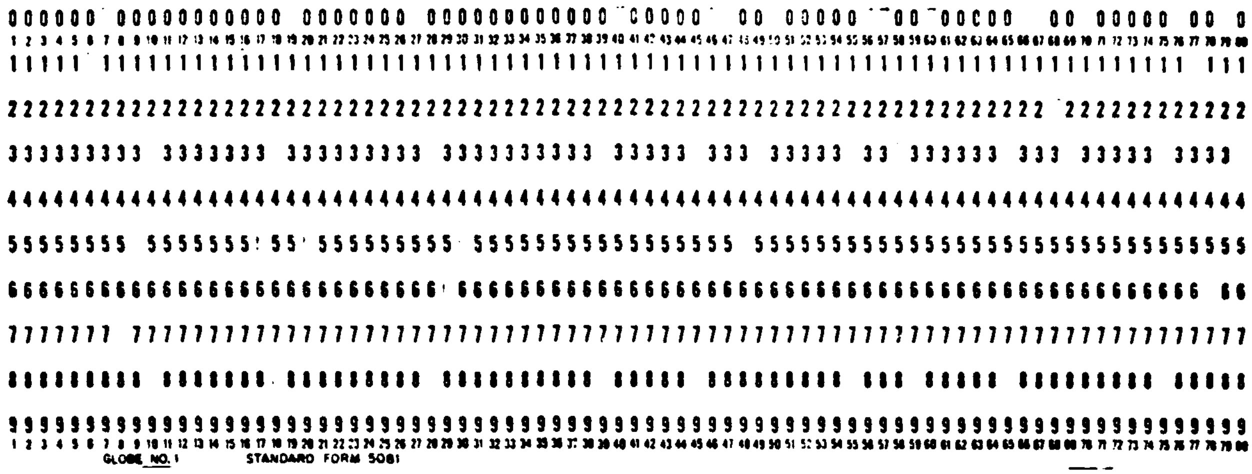


Data Card #40
Utility Company Monthly Charges for the Demand Rate Schedule
Variable Names: CHMTR, DCHPK, DCHOFF, ECHPK, ECHOFF, FLADJ

9000.



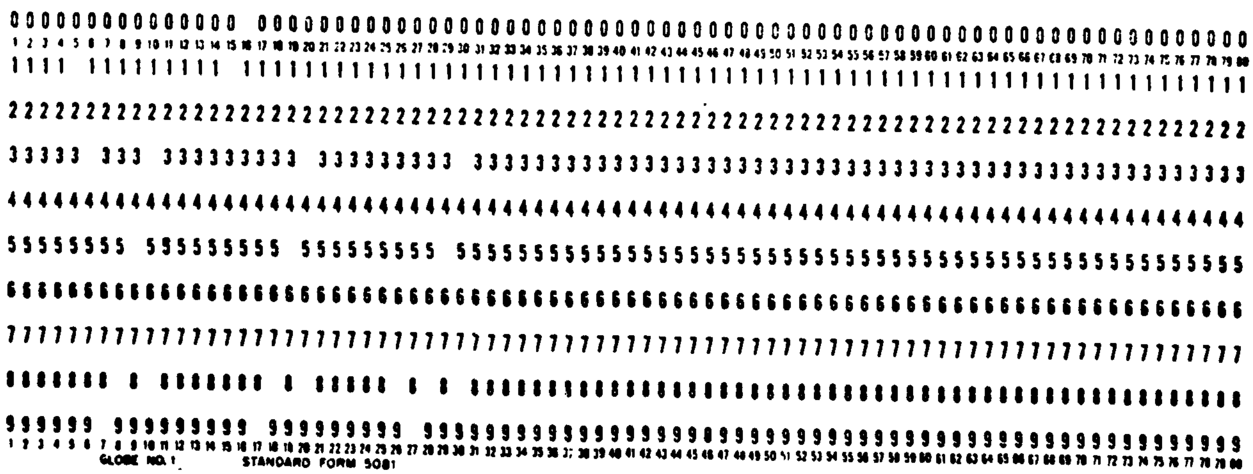
Data Card #41
Utility Company Billing Demand for the Demand Rate Schedule
Variable Names: DMDPK



Data Card #40

Utility Company Charges for the Time of Day Rate Structure

Variable Names: CHMTR, DCHPK, DCHMID, DCHOFF, ECHPK, ECHMID ECHOFF, FLADJ

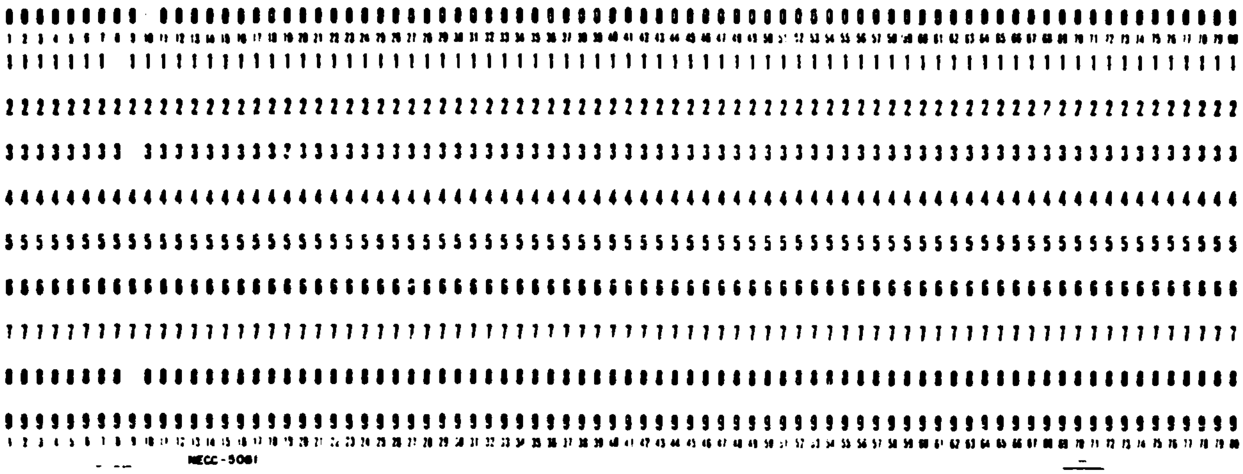


Data Card #41

Utility Company Peak Demands for the Time of Day Rate Structure

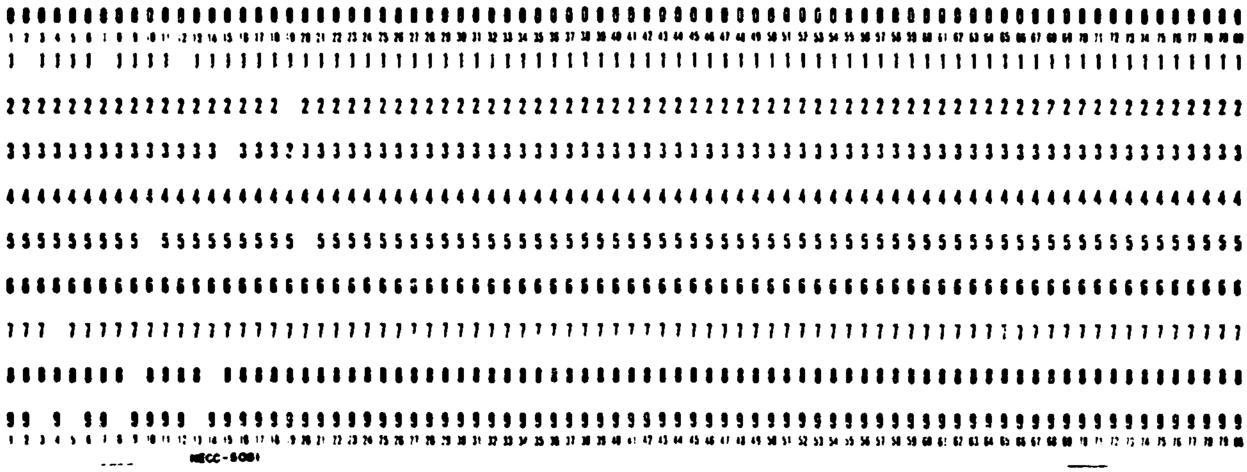
Variable Names: DMDPK, DMDMID, DMDOFF

1.0



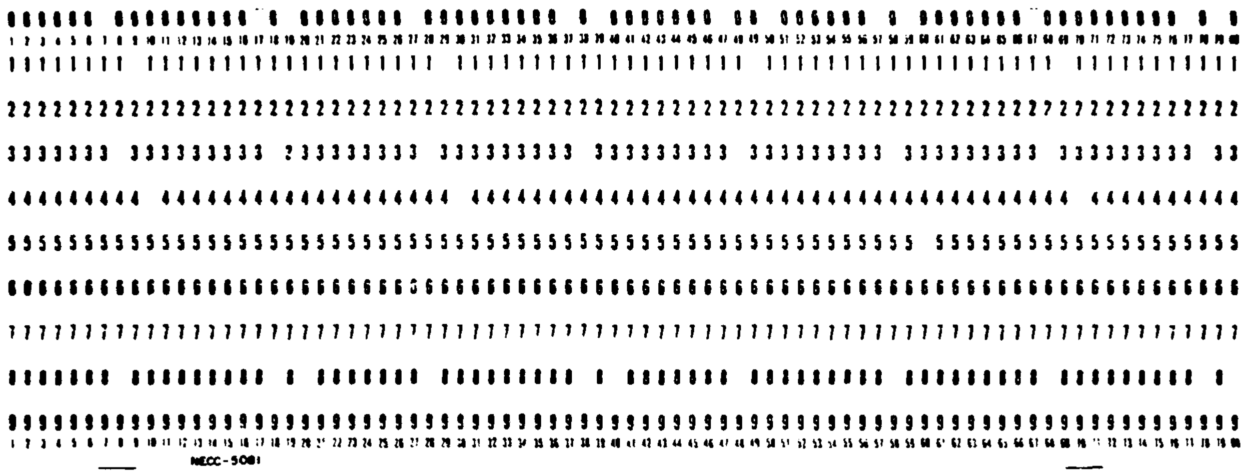
Data Card #42
Sales Price/Purchase Price Ratio
Variable Names: SALPUR

1979 1985 1983   25



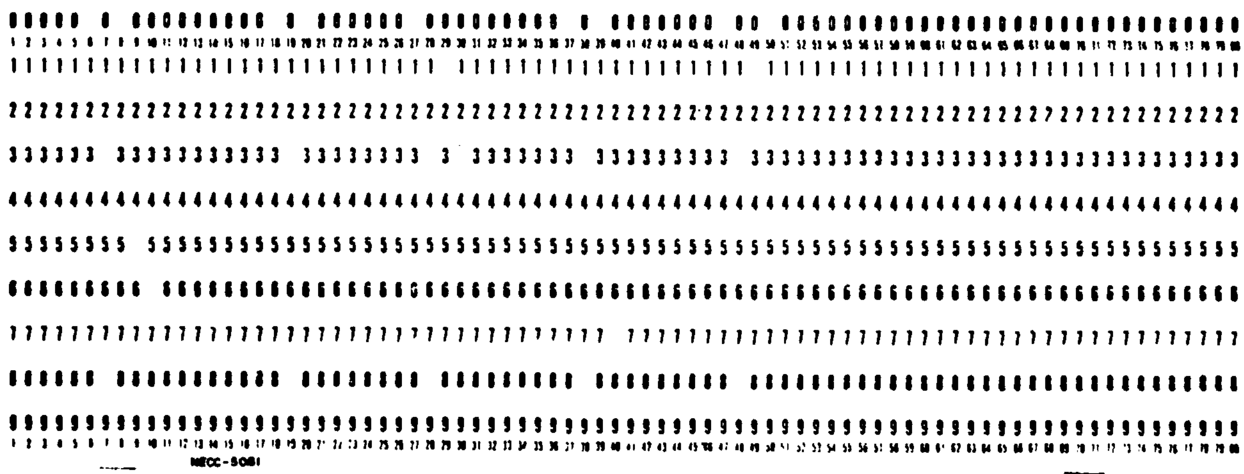
Data Card #43
Years Pertaining to the Life Cycle Cost Analysis
Variable Names: NOWYR, INSTYR, JYRCHN, LIFE

0.14 0.08 0.14 0.08 0.10 0.05 0.14 0.08



Data Card #44
Escalation Rates for the Life Cycle Cost Analysis
Variable Names: FESTGT, FELTGT, FESTDS, FELTDS, FESTST,
FELTST, FESTBL, FELTBL

0.056 0.0 0.13 0.07 0.10



Data Card #45
Escalation Rates for the Life Cycle Cost Analysis
Variable Names: OMESCS, OMESCL, ELESST, ELESLT, DISC

DATE

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